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THE FEDERAL POWER COMMISSION:
ECONOMIC ASSESSMENT AND LEGAL REFORM

Paul W. MacAvoy (M.I.T.)
Stephen Breyer (Harvard Law School)

570 - 71 November, 1971

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PREFACE

The Federal Power Commission is an entity with numerous responsibilities, and can be viewed as regulator, protector, employer, or political patron depending on the viewer's occupation. In this study, we view the Commission as a public enterprise, dispensing services to final consumers of electricity and natural gas. These services have economic dimensions of price, quantity, and income, and the point of the Federal Power Commission's activities is to change the prices and the quantities of public utilities, or to redistribute incomes from one group to another. Given these dimensions of Commission activity, this organization is found to be effective in terms of delivery of these services at the lowest possible costs.

Such an economic assessment leads directly to conclusions on appropriate public policy for the Commission. There are alternative forms of public enterprise, and of private enterprise, that would be able to deliver these "regulatory" services. Once the magnitude of the costs of the F.P.C. have been estimated, and comparable magnitudes also suggested for alternative regulatory forms, the choice can be made as to whether we should proceed with the Commission as it exists, or whether it should be appropriately modified to become "cost effective". The evaluation here leads to proposals for drastic alteration of Commission procedures, Commission responsibilities, and to new activities for other public and private companies in the energy industries.

This point of view does not encompass all aspects of regulatory activities, nor does it lead to all possible proposals for reform of the Federal Power Commission. There is no analysis here of the activities of particular Commissioners, of their individual performance and how they affected the trend of Commission decisions. Individual Commissioners have been important in changing the Commission for a time, but not for more than a few years. They have been constrained by rules and procedures, and by the "markets" in which they provide their services to such an extent that the "structural relations" must be more important. An alternative view might be that "if industries are being regulated wrongly, then it must be because bad people are doing the regulating." The alternative view invites support not found here.

There is much more to be done. The formulation of effective national energy policy, so as to develop stocks of fossil resources and new technology in nuclear fission in the least cost combination over time, involves a number of aspects of efficiency in regulation. These have not been dealt with

PREFACE

The Federal Power Commission is an entity with numerous responsibilities, and can be viewed as regulator, advocate, employer, or political nation depending on one's own position. In this study, we view the Commission as a public enterprise, dispensing services to final consumers of electricity and natural gas. These services have economic dimensions of price, quantity, and quality, and the point of the Federal Power Commission's activities is to change the prices and the quantities of public utilities, or to redistribute incomes from one group to another. Given these dimensions of Commission [illegible] activity, this organization is found to be effective in terms of delivery of these services at the lowest possible costs.

There is a general agreement [illegible] effective regulation on substantial public policy for the Commission. There are widespread views of study, interpretation, and of private enterprise, that seem to hold to [illegible] "regulatory" analysis. Some are supportive of the needs of the F.P.C. that have motivated and competent practitioners also suggested the alternative regulatory forms, but whether can be more to be approved as such a problem with the Commission as it exists, or whether it should be appropriately modified to achieve "good" performance. The evaluation here leads to proposals for greater utilization of Commission procedures, Commission [illegible] reduction, and to new activities for those public and private interests in the energy industries.

This study is also made for economists and students of regulatory activities, who want to learn of all possible dimensions that attach to the Federal Power Commission. There is no analysis made of the activities of individual commissioners or their individual performance, as they have affected the record of Commission decisions. The critical decisions have been important in shaping the directions for policy, but not for more than a few years. They have been understood as rules and procedures, and on the "general" attitude that provide these services as much as actual "cost" and "political balance" might be more important. In the case, it is attempted to treat the industries and [illegible] specific new concerns, [illegible] analysis. The alternative [illegible] levels we suggest are considered.

There is much more to be done. The conclusions of effective [illegible] general [illegible] are [illegible] the [illegible] in the [illegible] attempting to conclusions under study, including a number of [illegible] attaining its [illegible].

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here, nor have the national problems of environmental quality related to energy production. These are pressing and important problems -- more important, perhaps, than those dealt with here -- but they are touched upon only when they come within the purview of the Federal Power Commission. The center of concern is the Commission as an organization and how well it performs. It is our hope that the results fill in one cell in the body of public policy in the energy industries and that the other cells will be developed soon.

Paul W. MacAvoy

Stephen Breyer

Cambridge, Massachusetts
October 15, 1971

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1. The Activities of the Commission and their Costs

The Federal Power Commission is a typical independent regulatory agency, in that its statutory mandate requires it to control the profits and prices of certain firms with market power. The regulated firms transport natural gas in interstate commerce and sell electricity at wholesale, also across state lines. In practice, much of this Commission's regulatory activity seems directed less at controlling monopoly firms than at correcting the "social evil" caused by the tendency of high and rising prices to transfer income from consumers to producers. In fact, the regulation of natural gas producers begun in the early 1960's cannot be otherwise explained.

Price control is not the only activity of the Commission, however. The F.P.C. sees an obligation to improve the quality of natural gas and electric power supply. This requires that electricity and gas be produced and distributed efficiently and with due regard to the social costs (such as environmental costs) involved.

Such are the Commission's activities. The question is whether these are carried on in the correct proportion -- with due regard to improving the efficiency of the energy industries, and the price-cost performance of these industries. The thesis of this study is that the Commission has devoted far too much

time, effort and money to controlling prices and profits and far too little to the planning of national gas and electricity systems. There should begin to be some shift of the focus of regulatory philosophy from "price control" to "planning". This is not to say that, based on these findings, orthodox public utility regulation should be abandoned and that the Commission ought to become a design and planning agency. These are first round findings, and they lead to several specific suggestions for reform in Commission procedures that would lead to more economic use of resources in the regulatory process.

The first step in making these findings will be to describe the Commission's present regulatory task, and to make an assessment of the economic costs of performing these tasks. This is to show how the Commission presently spends its resources, and the relative importance it attaches to its various activities (where importance is measured in money terms). The purpose also is to obtain an overall assessment of the costs of regulation.

The assessment uses numbers wherever possible in order to give the reader some grasp of the magnitude of the amount of resources being expended. These numbers are sometimes very approximate. Thus, the reader should not let them convey a strong sense of confidence in the results obtained. They are perhaps the way to compare what otherwise would be incomensurable,

but no more can be claimed for them than that they represent best efforts to reach approximate results on size or scale of activity.

Costs are to be compared with benefits from the regulatory process. Chapter 2 will discuss in greater detail the most important area of Commission activity at the present time: the control of natural gas producers' prices at the wellhead. The discussion will lead to estimates of the economic benefits to consumers from these activities. Chapter 3 will analyze the price and profit controls put on natural gas pipelines and electricity transmission companies. This chapter will also evaluate the economic effectiveness or benefits from the public utility form of regulation. Chapter 4 will discuss the Commission's "planning" activities and the need for greater governmental involvement in the movement towards interconnected systems. Finally, Chapter 5 will provide a beginning assessment of the overall benefits and costs of regulation, and suggest several policy changes in agency procedure, statute law, and lastly in philosophical outlook.

Regulatory Activities and Economic Costs

During the 1960's, the Federal Power Commission solved a number of important administrative problems, in ways that demonstrated outstanding administrative abilities. At the

beginning of the decade, the Commission was faced with what one observer called an "administrative breakdown": its processes were paralyzed by efforts to analyze in detail the production costs of thousands of natural gas producers and to set individual price ceilings for each of them. By 1968, however, the Commission had cleared out the backlog of natural gas cases by reviewing large numbers of gas field sales in batches, and these "area rate proceedings" had received judicial blessing. Moreover, the Commission had reduced backlogs in other areas, by working out more rapid procedures for handling certification of new facilities, and by writing clear and firm "precedent cases" for setting gas and electricity rates. The Commission had made efforts to increase the effectiveness of its regulation by extending its jurisdiction over the wholesale distribution of electricity. It had become heavily involved in establishing "safe" and "reliable" national transmission of electricity, in the aftermath of the 1965 blackout in New York City and its report on this blackout.

By 1970, the Ash Council, established by the President to review the activities of the regulatory agencies, could find little specific to complain of in the Federal Power Commission's performance. The Council devoted only a few pages of its report to any discussion of this commission. The Commission's administrative behavior has been widely considered to be at least as

good as, if not better than, that of most government bureaucracies.

Whether the results that the F.P.C. has achieved are desirable, however, is quite another matter. The Commission has been regulating industries faced at the present time with severe economic problems. The Commission is at the center of public attention as members of the power industries, consumers and the Commission's own staff predict a serious shortage of natural gas. Electric power producers in some major cities have begun to find that they do not have sufficient capacity to provide full service at peak hours. At least some writers have argued that Commission regulation is partly responsible for these shortages. It may be the case that the Commission has devised admirable procedures for achieving economically deplorable results.

The effects of regulation have economic costs. The Commission can be viewed like a firm or an industry using resources -- money, time, and talent -- to provide the service of regulation. These costs include both those incurred as part of the Commission's own budget, and those imposed on defendants and intervenors in controversies before the agency and the Federal Courts. The Federal Power Commission at any time can show reduced expenses by rule-making that requires the companies to bear additional costs, or that requires final consumers to

bring cases and thus incur increased costs. The Commission could spend a great deal less by carrying out its usual activities at a slower rate -- but with the consequence of adding to the cost of delay incurred by the regulated firms. Both possibilities show that the regulation-related expenditures of all parties involved in proceedings should be considered the "costs of regulation." They should be included in the final balance sheet for the Commission.

Measuring the Commission's Product

The Federal Power Commission's day-to-day activities are very loosely organized around a few long-established programs, having their origins in the Federal Power Act of 1935 and the Natural Gas Act of 1938. These activities grew and took form as a result of thirty years of Federal Court review of the Commission's own decisions. One major motivation for these decisions has been to protect consumers against prices that were "unreasonable" or "unduly discriminatory".[1] To achieve the goal of "reasonable prices", the Commission has generally required

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[1] See, e.g., F.P.C. v. Southern California Edison Company 376 U.S. 205 (1964) on the jurisdiction and standards of the Commission for electricity prices, and F.P.C. v. Northern Natural Gas Company 346 U.S. 922 (1954) for "costs of service" and prices of natural gas pipeline companies.

that the companies sell electric power and natural gas at prices equal to the average "cost of service". The Commission has said specifically that prices for sales in individual transactions ought to be set close to "costs of service" as well, because the "cost of service formula is the one best adapted in determining just and reasonable rates in an industry where costs are known."[2] Thus, a major part of the Commission's job has been to protect consumers from large price-cost differences likely to occur in markets where individual producers can control supply. Congress has given the Commission jurisdiction in the sale of natural gas by producers to interstate pipelines, the resale of that gas by pipelines to retail utility companies, and the interstate sales of electricity for resale to local electric utilities.

The Congress has also given the Federal Power Commission the task of "assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources."[3] A similar mandate to provide more or "better"

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[2] In the matter of South Carolina Generating Company 16 F.P.C. 52 (1956) at 58. The qualifying clause "where costs are known" is important; in the many instances when there are widely varying estimates of costs, prices are not set equal to one of these estimates. The best characterization of the general relation is that "costs of service" provide a lower bound for prices suspected of being "too low" and discriminatory, and a much more approximate upper bound for prices found to be "too high."

[3] Cf. Section 202 of the Federal Power Act.

service can be implied from the Natural Gas Act for the interstate pipeline companies. The Commission can require the improvement and extension of a pipeline's service; and, in certifying new facilities both for producing electricity and for transporting gas, it reviews the entrant's financial resources and fuel capacity to see that it can "meet the demands which it is reasonable to expect will arise."[4] Moreover, the Commission is involved in the planning and forecasting processes in these industries, to a limited extent "encouraging" coordination in the operation or growth of larger systems.

Measuring the amount of benefits to the economy that these forms of regulation produce may be thought a utopian project. Indeed, even if many "value" questions are begged by defining benefits in purely economic terms, it is naive to think that the benefits produced by F.P.C. regulation in a given year can be measured with accuracy. Nevertheless, this measurement is undertaken to provide an estimate of the general magnitude of benefits or harm produced by regulation. The economic or social gains or benefits are defined in terms of what society or its members would pay to maintain the regulatory system. Estimates are made on the basis of the impacts on probable demands for gas and electricity at different regulated prices.[5]

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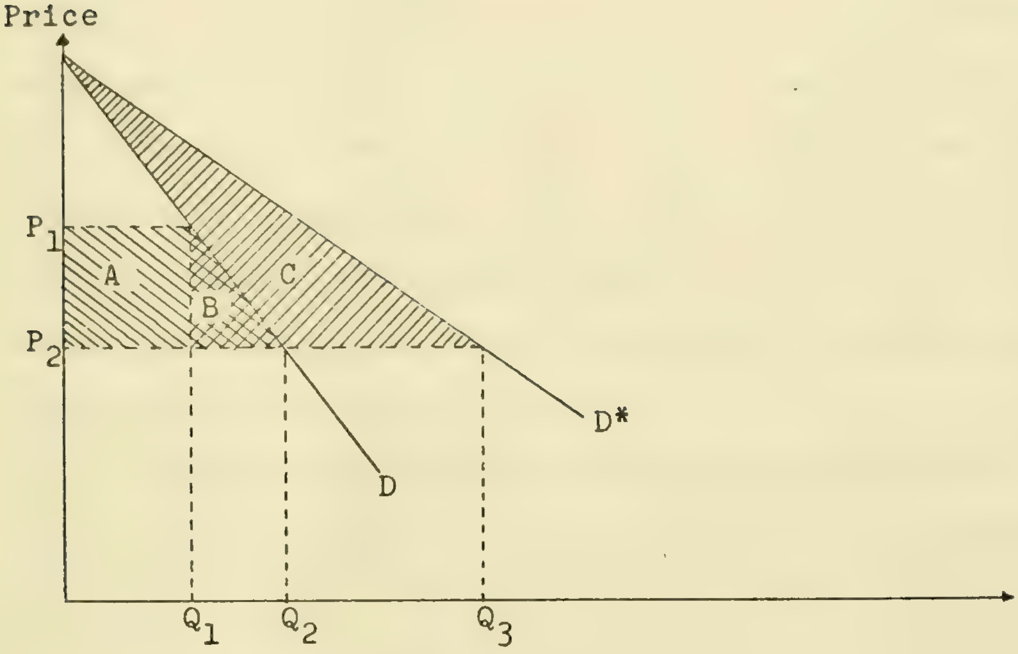
[4] Cf. In the matter of Kansas Pipeline and Gas Company and North Dakota Consumers Gas Company 2 F.P.C. 29 (1939).

[5] This is a comparison of consumers' benefits from different regulatory procedures, each opening up demand possibilities. Each level of demand $\bar{q}$ resulting from a level of regulated price

There are three categories of such benefits, as represented in the following diagram by shaded areas A, B, and C.

Figure 1



Quantity Demanded per Year

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[5] (cont'd). P can be estimated, so that the effects of degrees of regulation can be compared by comparing areas under $\overline{q} = f(\overline{P})$ for different $\overline{P}$. Each comparison is made assuming other factors affecting q are held constant, or their effects on q have been removed, as a matter of course. There have been a number of attempts made to make such comparisons; cf. Erickson and Spann, "Supply Reponse in a Regulated Industry: The Case of Natural Gas," Bell Journal of Economics and Management Science, Vol. 2, No. 1, P. MacAvoy, "The Effectiveness of the Federal Power Commission," Bell Journal, Vol. 1, No. 2, M. Peck, "Competitive Policy for Transportation?" in The Crisis of the Regulatory Commissions, P. MacAvoy (ed.), (W.W. Norton, 1970). F.M. Westfield, "Methodology of Evaluating Economic Regulation," American Economic Review, Vol. 61, No. 2 (May 1971), has objected to some of those studies on grounds that $\overline{q}$ is compared to q** from perfectly competitive price P**. This objection appears to be groundless, since this is not what the studies actually do, as even a quick reading indicates; rather they all make comparisons of $\overline{q}$ under alternative feasible regulatory policies.

Area "A" represents benefits that accrue to the consumer from a working year of Commission price control enforcement. Without ongoing Commission price surveillance, consumers would find price creeping up to level P_1 or failing to be reduced to level P_2. With regulatory surveillance (and accompanying review and case activities, all resulting in costs of regulation), prices are required to remain at P_2.[6] The consumers' gains are equal to $(P_1 - P_2)Q_1$, where Q_1 is the amount of service that would have been demanded at the higher price.[7] At the least, the Commission has claimed this as a measure of benefit from regulation of interstate gas and electricity prices.

Area "B" represents a further consumer benefit. Given that consumers' demands are represented by the negatively sloped demand curve D, the Commission-induced price reductions increase the quantity demanded from Q_1 to Q_2. This second consumers' gain is the dollar equivalent to what consumers would pay for $(Q_2 - Q_1)$ over and above their actual payment $P_2(Q_2 - Q_1)$ rather than go

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[6] The price would presumably be higher than this representative P_1 if the Commission were abolished, however. It is assumed here that the Commission is in operation, but at a much reduced level of expenditures on compliance, when P_1 is in effect. In fact, the upper limit of P_1 would be a price level clearly in violation of the precedents set by previous F.P.C. court cases dealing with that industry, so that a case without surveillance could be brought if that level were exceeded.

[7] Of course, this benefit to the consumer is achieved at the producer's expense. We shall assume at this preliminary stage that the consumer's gain is a social gain. This assumption is significantly qualified and revised in the chapters that follow (particularly Chapter 3).

back to price P_1 and quantity Q_1.[8] As such, it is an increase derived from direct price regulation and should accompany the area "A" benefits from "protection of the consumer."

The direct pursuit of "quality" by regulation also results in benefits for the consumer. Increasing the accessibility and reliability of service by Commission surveillance, for example, should shift consumers' demands from D out to a higher level, say at D*. This uncovers consumers' surplus, shown by the area "C", and increases the quantity demanded to Q_3. There are further benefits from planning that reduce social costs, or reduce the production costs of all the generating or transmitting companies. These benefits are not shown in the diagram -- since they are of the nature of decreased cost -- but when they are ultimately reflected in price reductions to the level of P_2, they add to "A", "B", and "C" benefits.

The critical question is whether measurements can be made of areas A, B, C accurate enough to use as part of an argument

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[8] See D. M. Winch, "Consumers' Surplus and the Compensation Principle," American Economic Review, Vol. 55 (1965), pp. 395-423. These gains are realized only under certain conditions. First, prices have to be greater than the economic costs of the additional output. The F.P.C.-defined "costs of service" are not economic costs, except by chance equality of accounting overhead allocations with the opportunity costs of this production. A second qualifying condition is as important: the $\Delta P \Delta Q/2$ measure is a good measure of aggregate gains of consumers only if their distribution is judged to be acceptable.

for maintaining the regulatory status quo or alternatively for regulatory reform. Several factors make any such estimate of benefits particularly uncertain. For one thing, estimates depend critically on detailed information about what market prices and quantities would be without regulatory surveillance, as well as what they are with surveillance. While there is sometimes information about market behavior before and after the onset of regulation, this information is difficult to use for assessing P_1,Q_1 and P_2,Q_2. Much of it is ambiguous. It is not sufficiently detailed to distinguish whether an increase in the quantity demanded has resulted from ordinary market growth or from lower prices produced by regulatory activity. Further, the F.P.C. calculates "costs of service" (c.o.s.) in such an arbitrary way that one cannot be certain whether, in setting prices equal to c.o.s., the regulatory price is in fact lower than the unregulated price would have been in the same market circumstances. Finally, information about "quality" of service in most cases is limited to quantity information, such as that on the extent to which plants are "out of commission". Accessibility and reliability are not assessed in terms of increased consumer demand, or in terms of reductions in the cost of using resources in these industries.

Despite these difficulties, it is possible to derive estimates of probable demands and probable prices that seem

reasonably valid. These estimates will be developed in detail in later chapters, when particular sorts of regulation are discussed and analyzed. They are based on the Commission's own estimates of the benefits that its regulation achieves. These, along with the estimates of the costs of regulation in the following sections of this chapter, provide a basis for deciding whether the Commission's activities at the present scale are worth the effort. If the administrative cost of regulation in a particular area does not produce substantial benefits -- beyond those likely from alternative administrative procedures outside of the Commission -- then regulatory activities in this area should be diminished.

The Cost of Electricity Regulation

The Federal Power Commission has broad authority to regulate the prices of companies producing or transporting electricity in interstate commerce. The procedures developed by the Commission are classical "public utility rate making" procedures, and will be discussed and evaluated in detail first.

The power company is regulated from the "birth" of a project to the day of final disappearance of the project from the balance sheet statement of capital assets. The chronological steps in the regulatory process begin with an application

for a "Certificate of Necessity and Convenience" by the company seeking to introduce service into some market. The certificate application -- or, in the case of hydroelectric power projects, a "license" -- is examined for the "sufficiency of demand" for the proposed service and the capacity of the company to provide the service. After certification has been granted and service begun, the reviews of prices are undertaken first by a hearing examiner, then by the Federal Power Commission on review of the examiner's decision, and finally by the United States courts on appeal of the decision of the Commission. The average price set by the Commission is close to the Commission's own judgmental estimate of the company's costs, including the costs of capital needed to maintain the service demanded. Finally, the Commission's staff takes steps to ascertain that the price ceilings set by the F.P.C. actually go into effect. All these activities require expenditures on Commission, Court, and defendant personnel and supporting resources.

These steps in regulation have applied to hydroelectric facilities since the passage of the Federal Power Act. In 1964, a court decision affirmed the Commission's power to set wholesale ceiling prices on all sales of electricity in interstate commerce. Since that time, the F.P.C. has proceeded to review and to regulate these prices. Companies have filed approximately 2200 rate schedules with the Commission each year, along with supporting

cost of service information, as part of these reviews. The Commission has processed these filed schedules, approving virtually all of them but subjecting approximately 50 of them each year to extensive "rate studies". Ultimately, approximately 30 of the rate studies have become the subject of formal proceedings or cases before the Commission concerning "rates, terms and conditions" of service. The disposition of the cases results in affirming the prices originally reviewed, or in rejecting these prices.

The Commission and the companies have incurred increasing costs from this expanded scope of regulation. The Federal Budget reports that the F.P.C. itself spent $1.6 million in fiscal 1968 on electric power utility regulation. Discussions and correspondence with a number of power companies indicate that simply preparing and filing an ordinary rate schedule has cost anywhere from $25 to $1000, spent on legal services and computer time. The total cost of more than 2,000 filings by the companies each year can then be conservatively estimated at $50,000.

Formal and informal rate studies and cases have been far more expensive. The Commission staff has initiated informal studies as part of its surveillance procedure. When preliminary reviews of rate schedules and annual cost reports have suggested the need for more complete analysis, the Commission staff has

requested extensive and detailed information on capital expenditures and output. A substantial portion of company executive and legal counsel resources must be devoted to providing this information. In 1968, 53 rate studies had been put into effect, most of them involving or requiring new attempts to calculate costs of service. If, as a number of power companies have indicated in private correspondence, meeting these requests for information costs more than $1,000 in each case, this stage in the annual regulatory review must cost the industry as a whole more than $50,000 dollars.

The informal price review, however, has been preliminary in many instances to much larger expenditures on formal cases. Approximately 30 cases have been in progress each year in the last few years (except when extremely large changes in economy-wide interest rates have precipitated the "stacking" of many more cases than 30 -- an exception to the rule related to the business cycle). During the three years in which any one of these cases has been "in process", both the company and the Commission have completed full costs of service studies, have held pre-hearing conferences, and then have undertaken hearings leading to a decision. All these steps involved investigations and testimony by company cost experts and executives, as well as the services of accountants, economists, and lawyers. Twenty-nine cases described in the 1968 Federal Power Commission Annual

Report had incurred costs that ranged from $7000 for proceedings on a single rate in Maryland to $305,000 for a full scale rate review on service to a group of cooperatives in North Carolina. A conservative estimate of the total economic costs of the 10 cases finished that year would be $1,500,000, which is an equally good estimate of the annual costs of any 30 cases in process.[9]

The total costs of regulation of wholesale electricity prices thus must be close to $3.2 million per year -- a figure that includes both Commission and defendant expenses. This estimate is conservative because it does not take into account the costs of any delay in electricity service due to a protracted series of proceedings; nor does it try to estimate the costs to any of the parties due to uncertainty about future prices and costs of service.[10]

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[9] This does not account for the possibility of lower or higher costs in any one year. If all cases were "single rate" cases, costs for defense might have been as low as $100,000; but if all were complex interclass rate reviews, then defense costs might have been $3,000,000.

[10] This estimate also does not include a further source of economic loss -- losses incurred by electricity generating companies selling to small buyers at uneconomically low rates in order to avoid expensive litigation before the Commission. The largest number of cases before the Commission involved small cooperative companies seeking to prevent a power wholesaler from "discriminating" against it by charging it a higher price than that charged another and ofter larger buyer. Cf. E-7129, E-7183, E-7273, E-7308, E-7344, E-7421, and E-7426 in Table 10 of the F.P.C.'s 1968 Annual Report (Washington, D.C.: U.S. Government Printing Office, 1969). One suspects that in fact the higher prices to smaller cooperatives reflected diseconomies of scale not present when electricity was sold to the largest retail buyers. Thus the trade-off would have been (a) reduced costs of litigation against (b) increased costs of production of electricity, and where the first exceeded the second, private losses were minimized but social costs incurred.

The Federal Power Commission also incurs substantial administrative costs as it pursues its program to add to the "quality" of service in electricity generation. This program has been centered on requiring the larger producers selling at wholesale to provide power to small retailers with whom these producers would prefer not to do business. So far, the campaign has had little effect though it has imposed significant costs on defendants in litigation before the Commission. The City of Gainesville, Florida, for example, requested the Federal Power Commission to require the Florida Power Corporation to interconnect; the Federal Power Commission examiner approved the request and also insisted that Florida Power pass on to Gainesville some of the cost savings arising from efficiency in large scale electricity generation. The Commissioners subsequently reversed the examiner and, in 1968 four years after the proceeding was begun, the City of Gainesville plea was denied by the Fifth Circuit Court of Appeals. This and subsequent "extension of service" cases have cost about $100,000 each to conduct. If two have been settled on average in a Commission working year, the annual cost of this regulation has amounted to approximately $200,000 per annum. Once prices have been set, the Commission staff has kept track of whether the company in its day-to-day operations has followed the Commission rules.

The company must use, for example, that capital equipment which is said was dedicated to interstate sales when it filed information on its production cost. The staff carries out "field surveys" to ascertain usage and rates; more than 200 electric utilities filed documentation on capital assets in use, and more than 350 companies filed studies of classification of original capital expenditures for purposes of completing field surveys in any year. Since these studies are sometimes useful to the firms in their own operations -- telling some firms, for example, where their capital equipment is located at that time -- the costs cannot be entirely attributed to regulation. But regulated companies still spend more on completing these surveys than do unregulated companies; nor have the regulated companies ever justified these surveys as cost effective because they have turned up "lost" capital equipment. In 1968, the F.P.C.'s own cost of electric power industry systems evaluation were \$1.3 million. A survey of a small sample of companies shows that they spend at least \$5,000 per annum on these activities.[11] On average, approximately 40 documentation and 75 classification reviews of facilities have been completed

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[11] This is a sample average for 30 firms showing "regulatory expense" on Form 1 of the electric power company reports to the Federal Power Commission. These firms did not have under way other proceedings mentioned above, or did not report costs related to system reviews.

each year, so that the administrative costs of the electricity surveillance program must have been close to $1.9 million per year.[12]

This review of the administrative costs of regulating the power industry shows that approximately half the costs have been attributable to price control activities and the other half to attempts to improve the quality of service. The companies and Commission together seem to have spent $3.2 million on rate or price regulation in a typical year in the late 1960's, although variations in the cost of individual cases may have made this amount as high as $4.7 million or as low as $1.8 million. They probably have spent an additional $3.2 million annually on certificate and systems evaluations to extend the quality and quantity of service. The total cost of this sort of regulation has ranged from $5 million to $8 million, and probably has been near to $6.6 million each year. These are probably the "costs of electricity regulation" in any one year, where the year has a case load close to that on average in the 1960's.

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[12] It is also assumed that the range of actual costs was between $1.4 and $2.4 million.

The Administrative Costs of Gas Field Price Regulation

Since 1954, when the Supreme Court decided Phillips Petroleum Company v. Wisconsin[13], the F.P.C. has been authorized to regulate the prices charged by natural gas producers for gas sold to interstate pipelines. But the Commission was unable to regulate producer prices effectively before the late 1950's. The initial efforts to set prices for each individual company failed because there were too many producers and the task was too complex (as will be shown in the next chapter). Records of "costs of service" were misleading or inadequate, for example when gas came from wells jointly owned by a number of producers each with different historical costs, or when a single producer's gas came from different wells that had different exploration and production expenses. Faced with having to make arbitrary cost allocations, and with having to allow a multitude of different prices in the same market, the Commission moved away from prices based on company "costs of service" and turned to setting area price ceilings, using as a base the area-wide average cost of exploration and development. In 1960, the Commission set provisional prices for "new" and "old" gas field contracts in 24 gas producing areas, and at the same time began proceedings

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[13] 347 U.S. 672.

designed to determine costs of service in various producing areas and thereby to set permanent area prices. In 1969, the Supreme Court affirmed the legality of the area pricing method and the particular prices set for the Permian Basin area, the first producing region that the Commission had reviewed. One can now expect the Commission to continue to set, and perhaps to adjust after various intervals, area rates as part of its ordinary regulatory activities.

The area proceedings have not entirely eliminated individual producer regulation. The Commission throughout the 1960's continued to issue Certificates of Necessity and Convenience to producers seeking to begin to deliver additional gas under new contracts with pipelines. The review has assessed the extent of each producer's gas reserves and the proposed sales prices before issuing the certificate. This review was designed to assure that the producer's reserves were sufficient and also that the proposed selling price was within the Commission's provisional guidelines for area rates. This type of individual producer proceeding, as well as the more extensive but consolidated area rate proceeding, has added to the Commission's administrative load.

The number of certificate proceedings has been large. For any recent year, there have been approximately 200 applications

for permanent certificates filed with the Commission. Approximately 1200 of these have been reviewed within the year in which they have been filed, and the remainder the following year. The proceedings for doing so have not been terribly complicated: they have considered proposed initial prices in terms of whether they were "in line" with others in the production area; this showing sometimes required studies of contract pricing in the region by lawyers and company accountants. Even though this change in procedure added some complication, the Commission at the same time has simplified the certificate granting process by providing for a "temporary Certificate". This has reduced the costs imposed by delay, since it has allowed new service to begin while the permanent certificate review was still going on. Reserve and other production facilities have not then been held idle by the certification requirements.

Permanent certificate reviews, despite the use of temporary certificates, have still produced significant costs in the form of regulatory delay. In the early 1960's, before the introduction of the temporary certificate, the cost of delay came to as much as .17 cents per thousand cubic feet of gas held idle in reserves for every month of delay. In fact, it has been shown that the delay had increased the costs of regulated interstate sales 3.5 per cent over and above the costs of unregulated

within-state sales.[14] The delay in introducing reserves into interstate commerce was more than five months at that time. The present delay, because of temporary certification, is far less; thus the price premium required by regulation cannot be as great as that in the early 1960's. Although the exact effect on costs is not known, at best the temporary certificates have reduced regulatory delay to 1 month, thereby lowering the cost of delay to .17 cents per Mcf for all new deliveries for one month, or $10 million per year;[15] at worst, temporaries have not dispelled the uncertainty of obtaining the final certificate and have made matters more difficult by allowing delivery under a contract that may ultimately be rendered null and void. In these worst circumstances, costs might approximate those of waiting for a permanent certificate; and, since permanent certificates have been issued on average six months after application

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[14] As documented by R.W. Gerwig, "Natural Gas Production: A Study of Costs of Regulation," Journal of Law and Economics, Vol. 5 (October 1962), pp. 86-88.

[15] The new gas certified each year cost more as a result of regulatory delay, $C_d = \sum^{n} c_i q_i \left[1 - \frac{1}{(1+r)^d}\right]$ where c_i is the present value of unit costs of gas quantities q_i in "n" individual contracts, and "r" is the monthly percentage costs of delay during the delay period of length "d." Given other regulatory procedures, c_i has to be not greater than initial base prices set by the Commission for field areas: these prices average close to 17 cents per thousand cubic feet, if it is assumed that contracts were for reserves from new fields discovered in 1967 and 1968. More than 60% of the new fields were in Texas, 10% in Louisiana, and the remaining in other states; weighting the F.P.C. ceiling prices by these percentages results in the $0.17 average. q_i is close to 16 trillion cubic feet, as shown on page 48 of the F.P.C.'s Annual Report for fiscal year 1968 (an amount that has a present value of 6 trillion cubic feet). With delay costs "r" of one percent per month for a "d" of six months, the certification procedure could cost as much as $58 million per year.

the delay costs could have exceeded $58 million per year.[16] Our judgment, based on discussions with gas producers as to the individual delays actually encountered by them and the costs of these delays, is that the most probable level of cost of delay in recent years has been $20 million per year.

These costs of individual contract regulation have been more than matched by the consolidated costs of area rate regulation. The area rate proceedings have consumed far more administrative resources than might reasonably be expected. They have been massive and prolonged. The first case began in December 1960 with hearings on prices of 351 companies for gas in the Permian Basin of West Texas. The hearing was completed early in 1964, a Commission decision followed in August 1965, and the Supreme Court affirmed the decision in May 1968. The Commission subsequently began to put these ceilings into effect in place of "provisional" or "interim" prices originally announced in 1960. Thus, the single area price proceeding took almost a decade to complete.

The Commission has begun four more area rate proceedings. Since they can in effect be built upon some of the evidence, findings, and experience of the Permian Basin, these new proceedings should take less time and legal resources to complete.

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[16] Cf. footnote 15 for calculations for the worst case. The most pessimistic estimate comes from assuming that the temporaries have zero value -- where the producer is indifferent between a temporary and waiting for a permanent certificate. These costs are the costs of waiting.

In all the area rate proceedings, the Commission has tried to find average costs of exploring for, developing, and producing new and old gas. It has then used these estimated costs to set future ceiling prices after adjusting them for any special conditions in the area. The important problems that have accompanied the search for these costs will be discussed in detail in Chapter 2. It suffices to state here that the lack of sound analytical technique for allocating joint costs incurred in exploring for and developing oil and gas presented serious and even critical problems. The administrative detail was greatly increased by these problems. In the absence of analysis, the cases dealt with "informed judgment" which led to testimony which consisted primarily of opinions of those experienced in the industry. Such testimony has been voluminous and controversial, to an extent that has made consensus impossible. Similarly, the analytical problems made it nearly impossible to rely upon historical cost as a basis for predicting future costs of developing new gas reserves. Although the Commission relied upon testimony of experts to set estimated costs, and to set rates of return on capital investment sufficient to compensate for the producer's risk of exploration and production, recent events -- in particular a serious shortage of additional gas reserves -- have suggested that the Commission's assessments

or expectations of costs were inaccurate. The difficulties of determining historical costs, and relating them to future costs and prices, multiplied the amount of required testimony and prolonged cross-examination and rebuttal hearings. The result was to add greatly to administrative costs, both direct costs and those resulting from regulatory delay.

The costs of the proceedings have been in the millions of dollars each year. The Federal Power Commission itself has spent more than $3 million annually on area rate proceedings to pay for staff preparation of briefs, testimony and drafts of decisions. The producers have undertaken extremely thorough and expensive investigations of drilling and production costs throughout the country. They have retained more than 50 law firms and more than a dozen economic and engineering consulting companies to provide testimony before the Commission. While their total costs have never been specifically calculated, the examiner in the Permian Basin proceedings allowed the producers to add 0.14 cents per Mcf to their production costs to cover expenses on regulatory proceedings, and uncontested industry testimony in the Texas Gulf Coast area rate proceeding stated that these producer costs amounted to 0.15 cents per Mcf.[17]

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[17] Cf. Area Rate Proceeding, et al. (Permian Basin, Docket AR 61-1, 34 F.P.C. 159 (1965) at 197; and the testimony of S.F. Sherwin, Exhibit 42-J (SFS-1), Schedule 17 in the Area Rate Proceedings . Dockets AR 64-1 and AR 64-2. These average fixed costs of regulation include the costs of certification and of rate schedule review, as well as those in the area rate proceedings, so that they are too large to be an estimate of the private expenses of the rate proceedings alone. But they are not far out of line as a measure of total costs of price regulation because most other schedule proceedings were suspended and replaced by area rate reviews.

Since approximately 75 percent of the 16 trillion cubic feet sold annually to the interstate pipelines have been subject to area rate regulation, these figures indicate that total producer administrative expenditures have been approximately \$18 million per annum.[18]

The remaining one-fourth of the sales to the pipelines have been regulated by the Commission on an individual review basis. Also, a number of producers have filed for exceptions to the Commission-set maximum field prices. The individual cases from these sources have not been dealt with rapidly; in fact, in 1968 the Commission completed its review of only 500 applications for rate increases, although more than 7500 had been filed. These proposed increases involved more than \$130 million. Technically speaking, the increases were "suspended" by the Commission and henceforth automatically took effect after five months in suspension. The technicality did not eliminate all costs of uncertainty and delay, however. Any increase that the firm collected under the "suspended" rate has been subject to refund to the extent to which it exceeded the Commission-determined "reasonable rate". Thus these 7,000 suspended rates may be subject to considerable costs in terms of uncertainty and delay -- costs that will be here noted, but cannot be estimated.

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[18] The producer commitments to interstate pipelines are given in the F.P.C.'s Annual Reports.

A number of the individual rate filings have led to formal producer "rate cases", particularly where area rates have not yet been set. Such cases have required the producer to document his production costs, from extensive statistical and accounting reviews of, for example, the cost of directional drilling for gas in a variety of producing regions. Litigation expenses in the recently completed rate cases have been in excess of $25 thousand on average; at this rate, the 80 cases dealt with in any recent fiscal year would result in total defendant's costs of $2 million per annum.[19]

Total administrative costs of regulating natural gas producers can be estimated from these various sources, but only very imprecisely. The Commission itself spends $3.1 million annually; the companies probably spend $20 million on the defense of rate cases -- if both large area rate cases and smaller individual rate reviews are included. The cost incurred by producers from regulatory delay at the certification stage is still more difficult to estimate. The range given here is from $10 million to $58 million, depending on the length of the delay.

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[19] The source of the data has been private correspondence with a reasonable number of defendants in the cases listed in fiscal year 1968. The costs do not include those incurred in removing rate suspensions in informal Commission proceedings; since more than 500 suspensions are reviewed each year, these total costs could be substantial -- albeit unknown at the present time.

On the assumptions set forth above, total costs range from $33 million to $81 million and approximate $43 million per year, in any recent year of Commission regulatory activity.

The Administrative Costs of Regulating Interstate Gas Pipelines

The price control process imposed on the long-distance natural gas pipeline companies is similar in many respects to that for electric utilities. Both the electricity generating companies and the interstate pipelines have some of the characteristics of "natural monopolies" -- there are technical economies of large scale in production or transmission that have been widely observed or acknowledged, and there have been no more than two or three sources of supply in any regional market as a result of these economies. The Federal Power Commission can regulate these few firms on the basis of detailed "cost of service" studies of each of them.

In the typical instance, the interstate pipelines purchase gas from producers in the field and resell these volumes on a day-to-day production basis to local gas distributing companies. Contracts are signed for the right to take reserves from field regions on a ten to twenty year basis, and resale contracts are signed requiring delivery over the same period. Some of the

pipelines have been so large that they have monopolized the sale of gas to local distributors in certain regions; others face competition in resales from two or three other pipelines. The Commission, therefore, has been in a position of being able to treat individual pipeline companies as "public utilities".

The central concerns of regulation have been prices and the entry of pipelines into producing and resale regions. Price controls have followed the procedures outlined for electric utility rate regulation. Entry control has been practiced to guarantee the "quality" of service to retail gas utility companies. The Commission has required pipelines seeking to build additions or extensions to their service lines, or seeking to add to gathering facilities in gas fields, to obtain a Commission "Certificate of Necessity and Convenience" before beginning construction. The Commission at the certification hearing has sought to determine whether there would be sufficient demand to warrant full capacity operation of the proposed pipeline and whether the pipeline has contracted for sufficient gas reserves to satisfy this demand.

To prove that both demand and supply are "sufficient", the pipeline must present enough field purchase contracts to demonstrate a ten to twenty year supply of reserves, and sufficient resale contracts to show a ten to twenty year demand

for these reserves. The F.P.C. has wanted the pipelines to demonstrate that any proposed facility will be fully used for its lifetime. This may be more than would be required by market conditions -- that is, the time lengths of these contracts are probably longer than the pipelines would demand were it not for the F.P.C.'s requirements. Still, the twenty year contract requirement reduces risks for gas producers, as it secures their sales; the requirement increases the risks for the pipeline and retailer, as they may not be able to sell all the gas they have purchased at compensatory prices in the far future. But the final consumer ultimately benefits because the contract requirements reduce the risk that gas service may be cut off. These changes in the burden of risk must be reflected in cost changes -- producers should find it easier to obtain capital, while pipelines and retailers should have more difficulty and experience higher economic costs of capital at the margin. Any overall increase in the cost of capital -- as a result of shifting the burden to an inefficient level of responsibility in the industry -- will be reflected in higher prices to the consumer. However, like the cost of delay for consumers of electricity, these costs cannot be readily measured nor can a price effect be detected at this time.

The administrative costs of licensing or certification procedures are extensive. The contract information, including

the signed purchase and resale contracts and also geological studies and legal documents establishing the distance of the underground gas and its ownership, have time and expenditure dimensions. There were more than 400 certificate applications before the Commission in 1968, involving 11,000 miles of new gathering and delivery pipeline and the processing costs for these extensions ought to be included in the costs of regulation (to be shown in the summary cost below).

The Commission's primary concern, however, has been with prices rather than entry. The control process includes both formal and informal proceedings. A pipeline wishing to begin service or to raise prices has had to justify the proposed price in terms of its (historical) average cost of providing service. The Commission's staff in a number of instances has disputed or denied the company's estimates of these costs. In such instances, the likely area of dispute has been (1) the proper allocation of fixed costs between different services, or between, for example, regulated sales to retail public utilities and unregulated sales to direct industrial consumers or (2) the proper rate of return allowed on capital investment. Both of these areas have contained the seeds of lengthy and possibly inconclusive conflict. Commission formulas for allocating costs -- as the Atlantic Seaboard Formula requiring half of all capital costs to be allocated to customers on the basis

of relative purchases and half on the basis of volumes bought during a designated peak-load period[20]-- have been extremely controversial when applied in particular cases. The controversy has had the effect of inconsistent application (either in the form of abandoning the formula entirely in some cases or of partial use of the formula). Generally, both companies and the Commission have often contested both the data and the manner in which the data have been applied with formulas to find regulated costs.

Estimates of the "proper" return to capital have been exceptionally controversial. These have depended on assumptions about possible alternative uses of capital by the investor, and about how much should be awarded the company for "good service". Both sets of assumptions have engendered dispute. In a typical proceeding, numerous financial and economic experts have described their judgments about required capital returns, leaving it to the examiner and Commission to sort out, evaluate and judge the correct value from alternative expert judgments.

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[20] The so-called "Atlantic Seaboard Formula" as given in Atlantic Seaboard Corp. et al. PUR (NS) 235 (1952). The costs assigned to service j are: $C_j = VC_j + (K/2)[Q_j/(Q_i+Q_j)]+(K/2)[Q_{jt}/(Q_{it}+Q_{jt})]$

where VC_j are total variable costs actually incurred in j, K is total capital cost, and Q's are volumes consumed by j and other i demanders throughout the year and also at peak-load period t.

The Federal Power Commission has exercised its right of review over nearly 1500 rate schedules each year in recent years. It customarily has suspended those calling for rate increases pending investigation. Then after informal conferences, the suspended rates either have been withdrawn or have become the subject of formal rate proceedings. Occasionally, the F.P.C. has initiated formal proceedings without waiting for a proposal for a rate increase -- not merely to prevent increases, but to lower rates already in effect. Both sorts of proceedings together have accounted for about 30 rate cases in process each year. After completing any one of these cases, the F.P.C. staff has carried out compliance reviews to make certain that price reductions flow through to final consumers of gas.

Altogether, these activities have cost the Federal Power Commission close to \$3.5 million per year.[21] The sum total of the private costs of regulation for the gas pipelines was \$2.5 million in 1968.[22] Changes in Commission procedures

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[21] The Federal expenditures for natural gas pipeline regulation are shown as \$3.526 million in fiscal year 1968, according to The Budget of the United States Government 1970, U.S. Government Printing Office (Washington, D.C., 1970).

[22] Compiled from "regulatory expense" and consultants' charges shown by each of the interstate pipeline companies in the F.P.C.'s "Form 2 Reports" contained in Natural Gas Companies (classes A & B) U.S. Government Printing Office, for 1968. Because of reporting omissions and errors in allocating costs, the range probably was from \$2.0 to \$3.0 million.

from year to year may change this total; increases in interest rates during periods of significant inflation also increase the total, by increasing the number of requests for rate increases. Over a decade, however, significant changes have been unlikely for the Commission has worked out fairly definite procedures which cost the defendants this or similar aggregate amounts.

Summary

There are substantial administrative costs involved in each of the Federal Power Commission's procedures. These expenditures are summarized in Table 1.

Table 1: THE ANNUAL COSTS OF REGULATION

Activity	Federal Power Commissions Costs Estimate (Millions of $)	Company Costs (Millions of $)	
		Estimate	Range
Electric Power Price Regulation	1.6	1.6	0.2 to 3.1
Electric Power Systems Evaluation	1.3	1.9	1.4 to 2.4
Gas Field Price Regulation	3.1	40.0	30.0 to 78.0
Gas Pipeline Price and Systems Regulation	3.5	2.5	2.0 to 3.0
General Commission Administration	1.1		
TOTAL ANNUAL COSTS	10.6	46.0	33.6 to 86.5

The cost of government activities has been roughly matched by those of private companies, in all types of regulation except gas field price regulation, where private expenditures have been 15 times greater.[23] Overall, the Federal Power Commission spent about $10 million and the companies spent about $50 million. These costs may vary from those shown for a typical recent year; in particular, the range of likely private expenditures may be from $35 million to $85 million per year. But we suspect that further analysis would only find that Federal Power Commission costs would be slightly lower and private costs slightly greater than those shown. The expenditures of all concerned have probably been close to $60 million and will continue to be at this level, in a single year of Federal Power Commission regulation.

These estimates of the annual costs of regulation are interesting for two reasons. First, they show how the Commission allocated the regulatory dollar and, in a sense, thereby reveal how the Commission expends "regulatory energy" among various categories of regulatory activities under its jurisdiction. Second, it reveals how much is probably being spent in

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[23] The minimum field price costs of $30 million include $10 million resulting from certification delay (assuming that the delay has been cut to a minimum of very few months), $18 million from area rate proceedings, and $2 million in other rate reviews and cases.

response to Commission initiatives, or to prevent further initiatives. The total Commission and private expenditures probably set minimum values on the benefits that regulatory activities must "buy" if the game is to be worth the candle. The chapters that follow attempt to assess these benefits. They discuss in detail just what regulatory "benefits" are "bought" by the administrative expenses just described.

2. The Regulation of Natural Gas Producers

In the past decade, the Federal Power Commission has devoted much energy, most of its initiative, and about 30 percent of its budget to regulating field prices for natural gas.[1] In this chapter, the regulatory methods that the Commission has used will be reviewed, and the economic effects of these methods will be assessed. The elements of industry structure will be sketched out first. Then an attempt will be made to determine the objectives of producer rate regulation. The ways of reaching these objectives are evaluated in detail and, finally, the costs and benefits of the ways chosen by the Commission are estimated. All of these considerations suggest that price regulation at the wellhead should simply be abandoned.

The Structure of the Industry

Before the Second World War, the difficulty of transporting natural gas for long distances made much of it an unwanted byproduct of the search for oil. In fact, natural gas "flares" illuminated the oil fields as producers deliberately burned off large volumes produced in the process of bringing oil to the

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[1] P. W. MacAvoy, "The Effectiveness of the Federal Power Commission," The Bell Journal of Economics and Management Science, Vol. 1, No. 2 (autumn, 1970).

surface.[2] During the war, however, the invention of large diameter thin-skinned steel pipe made possible the construction of long distance (thousand-mile) natural gas transmission lines that could take gas "packages" in Texas and deliver them over a ten to twenty year period to metropolitan regions in the Northeast for home and commercial consumption. Thus, today natural gas provides 35 to 40 percent of the nation's energy[3] from fields in Texas, Oklahoma, Louisiana and New Mexico that produce gas for supply markets in all the large metropolitan regions in the country (mostly from "dry gas" fields -- less than 25 percent of all gas used annually now comes from oil wells).[4] This demand for energy has produced a supply industry, made up mostly of oil and gas producers actively engaged in the search for and development of natural gas field reserves to be sold under long term contract for production into the interstate pipeline transmission systems.

The gas industry, like Gaul, is divided into three parts. First, producers search for gas by drilling wells on

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[2] C. Hawkins, The Field Price Regulation of Natural Gas (University of Florida Press, 1969), 2-3.

[3] Austral Oil Company v. Federal Power Commission, 428 F2d 407 (1970).

[4] Hawkins, op. cit., p. 221.

mostly leased land after paying a mineral royalty for the exploration rights. Upon finding an economic reserve or "package", they drill development wells to provide capacity for bringing the gas to the surface. Production puts gas into pipelines, first gathering lines that bring the gas to central field locations, sometimes to "refine" it so as to remove saleable liquids, at all times to deliver the dry gas into the transmission lines. All of the large integrated petroleum companies are in the gas production business, as are a few specialized gas exploration and development companies and most of the gas transmission companies (as well as many thousands of "independent oil operators" or "wildcatters" who account for the smallest proportion of total available volumes of gas reserves). Second, *interstate pipeline companies* transport gas to direct industrial consumers outside the field producing locations, and also to retail gas utility companies in metropolitan regions. They face diverse conditions in both purchase and sales markets. I~~t~~n purchase markets, there are now more sources of demand than there used to be. Before 1955, most gas supply fields were served by only one pipeline; but today in the larger fields, two or three or more different pipelines probably seek to purchase new gas reserves on long term contracts as they become available. In sales markets to industrial users, there may be a number of pipelines and also suppliers of alternative forms of

energy. In sales markets to retailers of gas, there may be two or more pipeline suppliers. Third, these gas retail distributing companies buy from the interstate pipelines and resell to industrial or commercial final users in their retailing districts. These companies are often local monopolies.

There is regulation throughout all the levels of this industry. State public utility commissions ordinarily regulate gas retail distributors. The Federal Power Commission regulated prices and profits of the interstate pipelines on sales to the retail distributing companies -- but not on direct sales to final industrial consumers. There is conservation regulation of the rate of output from fixed volumes of reserves at the wellhead in many states. In addition, in 1954, somewhat to the Federal Power Commission's surprise, the Supreme Court held in Phillips Petroleum Company versus Wisconsin that the Commission was responsible for regulating sales by the field producers to the interstate pipelines.[5]

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[5] Phillips Petroleum Company v. Wisconsin, 347 U.S. 672, (1954).

The Phillips Decision and the Development of Area Rate Regulation

Arguments about the validity and implications of the Supreme Court decision have made producer regulation an important political as well as economic issue. Debates about whether producers should be regulated have raged before the Commission, in the Courts in further cases, and before Congress. Despite the sometimes extreme criticism of the decision, however, the Court's logic in that case is neither wholly unreasonable nor totally satisfying.

The Court held that language in the Natural Gas Act provided for producer regulation. The language itself is ambiguous. The Act states that "the provisions of this chapter shall apply to the sale in interstate commerce of natural gas for resale ... but shall not apply to the production or gathering of natural gas."[6] A field producer's sale to an interstate pipeline is "a sale in interstate commerce for resale" but there is also an exemption in the act for "production or gathering" of natural gas. Whether the exemption applies is not clear, because it may be restricted to the physical production and gathering operations themselves or to

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[6] 15 U.S.C., Section 717(b), (1964).

those operations and the sale of what is gathered.

Although the legislative history of the Natural Gas Act has little to say about producer regulation, what is said seems to support the Supreme Court's decision. The House of Representatives Committee Report states that the words 'production or gathering' are "not actually necessary as the matter specified therein could be said fairly not to be covered by the language affirmatively stating the jurisdiction of the Commission."[7] This statement, if accurate, suggests that Congress did not mean to exempt from regulation the sale by producers to pipelines at the wellhead, for such sales surely could be said "to be covered by the language affirmatively stating the jurisdiction of the Commission" over sales for resale in interstate commerce.[8]

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[7] House of Representatives Report Number 709, 75th Congress, 1st Session 3 (1937). See also Note, Legislative History of the Natural Gas Act, 44 GEO. L.J. 695 (1956).

[8] The language in the Act would appear to have been fairly clear to the producers and transporters involved. Before 1954, the producers themselves feared the Act would be interpreted to require the regulation of field prices. Although the Federal Power Commission consistently refused to regulate producers, at the urging of the oil and gas companies Congress passed a bill in 1949 granting a clear producer exemption -- a bill that President Truman vetoed. The producers, the Congress, and the President all acted as if without a new law the producers might be regulated.

Despite the logic of the Court's position, however, it might still be criticized, although at a somewhat deeper level. Although its opinion is consistent with statutory language and some of the legislative history, the Court did not examine the economic purposes that producer regulation might serve. Without such an examination, the Court could not tell whether producer regulation was a consistent application of public policy, in the sense of being consistent with regulation of monopoly or oligopoly transmission companies or monopoly retail distributing companies in the gas industry. If this was not the case, to assume a Congressional intent to regulate in the face of ambiguous language and a near-silent legislative history would not be acceptable legal procedure.[9]

Given the result of the Court decision in Phillips Petroleum v. Wisconsin, Congress passed a bill exempting field sales of natural gas from regulation. President Eisenhower vetoed the bill. He did so, not because he favored regulation, but because he disapproved of certain producer lobbying tactics.[10]

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[9] We shall not pursue this question immediately here, but much of what we say in the rest of this chapter bears upon it directly. To what extent the Court, in 1954, could have been aware of the facts and arguments on the economic rationale for regulation, we leave to the reader to judge. Still, we think they show that the Court had no acceptable rationale for interpreting the statute as they did.

[10] Those that overtly suggested that the producers would provide campaign contributions in return for votes. See E. Kitch, "Regulation of the Field Market for Natural Gas by the Federal Power Commission", Journal of Law and Economics, Vol. 11, p. 243 at 256 (1968).

Once it became clear that Congress was not going to exempt producers from field price regulation, the Federal Power Commission began to struggle with the problem of how to regulate. The first approach was to treat producers as individual public utilities, looking to individual costs and prices designed to recoup these costs. After this proved unwieldy, the Commission set ceiling prices for groups of producers, allowing individuals to charge less than, but no more than, the ceiling. In 1960, the Federal Power Commission divided the major gas producing regions into five geographical areas[11] and began hearings to determine proper ceiling prices for each area. The first hearings began in 1960 and resulted in price ceilings for the Permian Basin region of West Texas - New Mexico, which finally received Supreme Court approval in 1968. Since 1968, one other proceeding -- on ceiling prices for Southern Louisiana -- has passed through both the Commission and the Courts (only to be reopened recently to allow higher prices).

The Commission has operated to set limits on prices prospectively, i.e. henceforth from the time an "area rate proceeding" is completed . This did not control producer prices during the

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[11] The five areas were: (1) The Permian Basin (Texas and part of New Mexico), (2) Southern Louisiana (including the offshore area in the Gulf of Mexico), (3) Hugoton-Anadarko (part of Oklahoma and Kansas), (4) Texas Gulf Coast, (5) Other Southwest (Mississippi, Arkansas, parts of Alabama, Texas and Oklahoma).

many years that the proceedings have been in progress. To set interim ceilings, the F.P.C. worked out a legally complex, though practically simple, procedure. Price increases for existing contracts presented little problem, for the Commission suspended these for five months; after five months, they took effect subject to an obligation to refund any excess above the "reasonable rate". This was interpreted to provide customers with the difference between the interim price and what the area rate proceedings ultimately decided was the "reasonable" price. Prices for new supply contracts have been controlled by the certificate issuing procedure.[12] The Commission, with the help of the Courts,[13] developed the practice of withholding certificates unless the producer agreed to sell the gas at prices that the Commission posted as (provisionally) reasonable. The Commission issued a list of price ceilings for the various producing areas -- ceilings which were only slightly higher than the prices for new gas in those areas in 1960. While the Commission did not rigidly adhere to these guidelines, the object seemed to be to hold new gas prices "in line" with those

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[12] Natural Gas Act, 52 Stat. 821 (1938), 15 U.S.C. Section 717 (1964).

[13] See Atlantic Refining Company v. Public Service Commission of New York ["CATCO"], 360 U.S. 378 (1959).

charged in the late 1950's and early 1960's.[14]

Because the area rate proceedings lasted through the decade, the provisional prices held all new contract agreements to levels near the 1960 unregulated average. The first complete area rate proceeding in 1968 set prices for the Permian Basin only slightly higher than the provisional (or 1960) prices. The second proceeding set ceiling prices for Southern Louisiana at about the 1960 level until the reopening of the case when the ceiling was raised by about 25 percent.[15] Since the remaining area rate cases are still in progress, the status quo is as if contracts for new reserves found in the early 1970's were being written under conditions existing in the early 1960's.

The Objectives of Producer Price Regulation

The Federal Power Commission has been slow to complete the area rate proceedings, and they have been expensive in terms of numbers of millions of dollars spent on lawyers, consultants, and expert witnesses. Whether this is "good regulation" depends on the reasons for wanting to regulate gas producers at

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[14] See Federal Power Commission, Statement of General Policy, No. 61-1, 24 F.P.C. 818-820 (1960).

[15] See Opinion #598, Area Rate Proceeding (Southern Louisiana Area), issued by the Federal Power Commission, July 16, 1971.

all. In fact, there are two conceptually distinct purposes that this regulation might serve. The fact that neither the Commission nor the Courts have made much effort to distinguish between them has made the task of regulating more difficult.

(1) Control of market power is a traditional economic rationale for regulation. Stated in simple and direct fashion, it can be argued that where one firm or possibly a very small group of firms produces the entire output of an industry, that output will be less than the amount provided by competitive suppliers. The monopoly or oligopoly firms with the power to restrict market output will carry out restrictive policies to increase the market price -- so as to add to net revenues (via a higher price-cost margin) more than is lost in restricted output. If it is costly to introduce competition into the industry via antitrust policies -- perhaps because economies of scale make production by more firms less efficient -- the government may try to regulate the level of prices directly (so as to reduce price and thereby increase output to an amount approximating the competitive level).

The demands for control of market power and of arbitrary price behavior led to state regulation of gas distributors and Federal regulation of interstate pipelines. These demands have

also been used to justify producer regulation. It is asserted that gas production is concentrated in the hands of a few producing companies -- so few that the largest producers can raise the price of gas above the level that competition would otherwise dictate. Unless market power at the wellhead is checked, pipeline regulation will not be wholly effective, for consumers will still have to pay monopoly wellhead prices for gas which are then passed through as "costs" of the pipelines and retail distributors. In the words of the Supreme Court, "the rates charged [by producers] may have a direct and substantial effect upon the price paid by the ultimate consumers. Protection of consumers against exploitation at the hands of natural gas companies was the primary aim of the Natural Gas Act."[16] On this rationale, the Federal Power Commission should determine the price at which gas would be sold under competitive conditions and forbid sales at higher prices.

The market power rationale has turned out to be an important argument in the early history of the producer regulation controversy, but has waned during the later controversy on how to regulate and whether to continue. The accumulated evidence has come to the point where the conclusion is that gas producers do not possess market power; but rather, gas sales take place

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[16] Phillips Petroleum Company v. Wisconsin, op. cit., at 685.

under competitive conditions. As the Fifth Circuit Court of Appeals recently pointed out, "there seems to be general agreement that the market is at least structurally competitive."[17] The structure of markets has been roughly indicated by the extent of concentration in the production of gas. The Federal Power Commission statistics show that for 1960 the largest gas producer accounted for 8.5 percent of all sales, the 15 largest shared 50 percent of the market, and remaining sales were accounted for by thousands of small producers.[18] These are indicative given a very "wide" market, but in a much more narrowly contrived market, for example in the Permian Basin, the five largest producers accounted for 50 percent of production.[19] Professor Adelman has characterized this degree of production concentration as "low," in fact "lower than 75%-85% of industries in manufactured products"[20] and Professor McKie has shown that entry into the industry is so unimpeded that even if concentration were higher here than elsewhere, the largest producers would not be able to systematically charge higher than competitive prices.[21]

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[17] Austral Oil Company v. Federal Power Commission, op. cit., at p. .

[18] C. Hawkins, op. cit., p. 248.

[19] See Austral Oil Company v. Federal Power Commission, op. cit., at p. .

[20] Testimony of Professor M.A. Adelman before the Federal Power Commission, Champlin Oil and Refining Company, Docket #G-9277, p. 458 L.C., quoted in MacAvoy, The Crisis of the Regulatory Commissions (W.W. Norton, 1970), p. 156.

[21] J. W. McKie, "Market Structure and Uncertainty in Oil and Gas Exploration," 74 Quarterly Journal of Economics 543 (1960).

The rejoinder to these indicators of wide ownership of production is that the market is made in sales of rights to take from new discoveries of reserves, and ownership of uncommitted reserves has been highly concentrated. There has been some suspicion that this market has been "thin" to the extent that a few producers have been able to raise prices on new contracts for additional reserves, and then pass these through to all production by triggering "favorite nations" clauses in the old contracts calling for comparable old contract prices. But there has been no basis for this suspicion -- the economists for the distributing companies putting forth this view before the Federal Power Commission have not presented evidence on shares of large producers of new reserves showing high concentration. More neutral sources of evidence are to the contrary. Indeed, the only study seeking to find concentration in new reserve sales shows that the largest 4 companies provided only 37%-44% of new reserve sales in West Texas-New Mexico, 26%-28% in the Texas Gulf region, and less than 32% in the Midcontinent region -- all in the 1950-1954 period just before the Phillips decision. These levels of concentration in supply of new reserves were all less than half the concentration in demand for these reserves accounted for by the 4 largest pipeline buyers in each of these regions. Power to control new contract prices probably did not exist on

either side of the market, but if there were "a balance" then it lay with the pipelines rather than the producers.[22]

These structural indicators may not be decisive. Certain proponents of regulation, such as the gas distributing companies, have argued that despite its apparently competitive structure the producing segment of the industry behaves non-competitively. They have at times pointed to the rapid rise in the field price of natural gas between 1950 and 1958 as performance not in keeping with competitive norms (prices rose from 9 cents per Mcf to a peak of 24 cents per Mcf in the Gulf Coast region). Economic studies of the markets and thousands of individual contracts suggest to the contrary. Rather, during the early 1950's the presence of only one pipeline in many gas fields effectively allowed the setting of monopoly buyers' (monopsony) prices for new contracts of gas. Thus the field price for natural gas was often depressed below the competitive level because of the lack of effective competition among buyers. During the next few years, several pipelines sought new reserves in old field regions where previously there had been a single buyer, and this new entry raised the field prices to a competitive level from the previously depressed monopsonistic level. Competition, rather than market power,

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[22] Cf. P. W. MacAvoy, Price Formation in Natural Gas Fields (Yale University Press, New Haven, 1962) chapters 5, 6, and 7.

accounted for much of the price spiral that was claimed to show the need for regulation.[23]

Proponents of regulation have also argued that competition among producers has not been effective because their pipeline customers have not had sufficient incentive to bargain for low prices. Since pipeline profits are regulated, the transmission company can "make the same return" regardless of the purchase price of gas and can pass any purchase price increase on to the consumer. The argument on its face is suspect, because of the existence of large expenditures on capital as well as current expenses for gas supplies. The argument on capital is the same -- prices can be passed on -- except that a rate of return can be earned on the higher capital prices. Given a demand limit ultimately on what can be passed on, the regulated firm should prevent enhancement of fuel prices (on which no rate of return is earned) in favor of enhancement of capital prices (on which there is a rate of return).[24] Here too

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[23] Ibid., p. 9, and chapter 8.

[24] On this point, the economic theories of the regulated firm agree. The Averch-Johnson theory of the profit maximizing firm subject to a constraint on rate of return implies absolutely no enhancement of the price paid for a non-capital input factor. Cf. H. Averch and L. L. Johnson, "Behavior of the Firm Under Regulatory Constraint", American Economic Review, Vol. 52 (December, 1962), pp. 1053-1069. See also W. J. Baumol and A. K. Klevorick, "Input Choices and Rate of Return Regulation: An Overview of the Discussion", The Bell Journal of Economics and Management Science, Vol. 1, No. 2 (autumn, 1970), pp. 162-190.

empirical study suggests that pipelines in fact bargained for minimum prices. In the 1950's wherever possible, pipelines pushed field prices below competitive levels and, when the low price threatened to drive producers out of exploration and development, rather than raise prices for all producers the pipelines themselves went into the exploration business. The selective production of higher cost gas with monopsony pricing on the low cost gas must have reduced payments of producers' rents to a minimum.[25]

There are many reasons why pipelines would like to keep field prices low. A low price, when passed through to final consumers, implies a greater demand for gas, possibly allowing the company to expand its service and increase its investment. This can be exceptionally profitable if regulation is not so severe as to hold the rate of return on the additional investment to the level of the marginal economic costs of capital (the Federal Power Commission is not that severe, as will be seen in Chapter 3). The lag structure in regulation also works to the benefit of the pipeline, if purchase prices of gas can be kept down. If the pipeline can buy at prices lower than the regulatory commission anticipates, it may earn extra profits in the period before the agency can reset the

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[25] Cf. P. W. MacAvoy, Price Formation in Natural Gas Fields, op. cit., in particular chapter 5, "The Sale of Reserves in West Texas and New Mexico."

pipeline's resale prices. The conclusion must be that there is neither reason nor results that show non-competitiveness in field pricing.

Finally, those favoring regulation have pointed to producer profits as evidence that field price controls are necessary. Persistent earning of profits higher than the average in American industry conceivably does indicate the presence of higher-than-competitive prices.[26] In fact, profits would appear to be "higher". Economic experts appearing for the distributing companies in the Permian Basin Area Rate Proceedings reported average profits of between 12 and 18 percent for oil and gas companies at a time when the average return on capital in manufacturing was slightly less than 8 percent.[27] This profit comparison, however, is far too unreliable to suggest the presence (or the absence) of monopoly pricing, due to three special features of returns in the gas producing industry.

First, without regulation, the marginal producers must earn a return on their capital at least equal to what they could earn by investing elsewhere. But lower costs on more fortunate discoveries in a world of uncertainty might earn much

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[26] See the Permian Basin Hearings, F.P.C. , at . Cf. C. Hawkins, op. cit.,

[27] The Federal Trade Commission, Report in the Council of Economic Advisors, Economic Report of the President, 1960.

more. This extra profit or "rent" is also earned by unusually efficient or fortunate producers in other industries. However, there are important reasons for believing that there are more intramarginal rents earned in natural gas production than in many other industries. If so, average profits are greater in natural gas production despite considerable competition, and despite conditions at the margin of unexceptional profits.

Secondly, the Permian Basin profit figures reflect profits only of firms still in business, not of those that have failed. If the rate of failure in natural gas is higher than in other industries, the return that successful firms receive must be higher to take into account this greater risk. The uncertainty in exploring and developing gas -- seven out of every eight exploratory wells are dry -- suggests that risks of failure are unusually high, particularly for the small individual wildcatter. A large number of wildcatters goes out of business each year, but there is no record of the exact number or the amount of investment on which returns are negative. Even so, it is reasonable to assume that the "failure rate" is higher than average.[28]

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[28] The risk envisioned here is "business risk" encountered by the decision-maker of a firm that most probably is also the equity holder. In these circumstances, the failure or bankruptcy of the company may be important to the decision-maker in and of itself, separate from the financial impact of the failure in the form of reorganization of assets. This concept of "business risk" is developed in P. H. Cootner and D. M. Holland, "Rate of Return and Business Risk", The

Thirdly, the profit figures in the Permian Basin Proceedings overstate the true return to capital because of the accounting procedures used. The rate of return estimates were calculated simply by dividing total profits that producers report they have received by the total capital that they report they have invested. This does not account for the extensive time lag in this industry before an investment begins to earn a return. The accounting return on a dollar invested here must be far lower in real terms than elsewhere if payment begins five years, rather than one year, after the investment is made; the simple accounting profit rate must be adjusted to take the long lag between exploration and production into account. Producer witnesses in the Permian Basin case estimated that an "apparent yield" of 16 to 18 percent was equivalent because of the lag in production to a "true yield" of about 10 percent.

In any event, for all these reasons, not much can be concluded from the profit figures. Our conclusion is that the competitive market structure and previous studies of price

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[28] (cont'd) Bell Journal of Economics and Management Science, Vol. 1, No. 2 (autumn, 1970), pp. 211-226. It should be distinguished from the financial risk undertaken by stockholders purchasing shares in a national capital market who are able to form portfolios of shares of large numbers of corporations. Here the risk is that of loss on the portfolio, compared to the "capital market" at large. Our view is that business risk will be substantially greater in the owner-manager companies responsible for exploration and development in oil and gas than in more highly concentrated industries.

behavior indicate that producers do not have significant power to raise prices above long term marginal costs. This conclusion is more generally accepted now than fifteen years ago; the Supreme Court in 1968 referred to gas producers as "intensely competitive."[29]

If this view on competition is correct, then to regulate as if firms have market power can in principle do nothing but cause trouble. The Federal Power Commission, with this rationale for regulation in mind, would reduce prices in search of the competitive level, but in fact would necessarily set them at a lower level because they were already competitive before the reductions began. A lower than competitive price stimulates demand, leading some buyers to use natural gas though the economy could provide for their needs with other fuels at lower real costs (in terms of resources expended); the lower price would also reduce incentives to supply new reserves and production, for it would not cover the cost of providing returns to the producer now at the margin. The regulation-induced increase in the quantity demanded, and decrease in the quantity supplied, would necessarily cause a shortage.

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[29] This is not to suggest that it is universally held, however. Members of the staff of the Federal Power Commission and economists employed by the retail distributors are still not totally convinced.

There is a second theory that is claimed to justify regulating producers. This would apply even if there were highly competitive conditions of market structure, and if prices were being set at a competitive level.

(2) Regulation to reduce rents and windfalls. The description of a competitive market necessarily emphasizes the behavior of the marginal producer and the marginal consumer, since they set prices and outputs for the entire market. Prices in a competitive market are equal to the cost of producing the marginal units that can be sold -- so that the producers of less expensive intramarginal units receive the market price and consequently realize "rents" or "quasi-rents" of returns over and above resource costs. These rents are asserted to be exceptionally high in the gas and oil industries.

Although there have been no estimates made of the amount of rents that gas producers would earn without regulation, there are reasons to believe that rents would be large when compared to those earned in other industries. For one thing, gas is a wasting resource whose presence in the ground in commercial quantities is uncertain until exploration and development are complete. At that point, the value or price is set by the cost of marginal additional exploration (when demand is

increasing sharply, as it has been in the last two decades). The difference between this price and the production costs of fully explored reserves should constitute an appreciable windfall. Of course, windfalls of this sort go in part to land owners who do not themselves produce gas but who have the ownership rights to the ultimate scarce resource (the location or site of the in-ground reserves). Strict control of producer prices would deprive producers of such windfalls and prevent them from being paid over to the landholders.

There is another reason why windfalls may be substantial. The cost of finding and developing gas reserves has increased considerably over the past two decades. Thus, gas found and sold to pipelines fifteen years ago in reserve commitments, but still not produced, would still have lower costs than new reserves. If this "old gas" were to be priced at presently prevailing long term marginal exploration and development costs, then there would be appreciable windfalls or rents received.

Proponents of regulation seek to eliminate these windfalls and rents without interfering with the market clearing mechanism. To do this -- to clear the market of excess demand -- one would have to hold down the price of intramarginal volumes of gas while allowing marginal units to be sold at a price that equals long term exploration and development costs. In effect, regulation that sets differential prices on each unit of supply might

force the producer to pass the windfall on to the consumer.

This type of regulation would be somewhat unusual, but not unheard of. Differential regulated prices are most commonly found in housing, where rent control laws may hold the price of existing housing at previous levels, while allowing the price of new housing units to be set so as to clear the market of demands for rentals. But this approach requires extraordinary sensitivity to supply, and even in the best of conditions, probably some rationing procedure. Where the primary aim is to bring about a certain distribution of income -- away from windfall gains to producers, towards higher real income for consumers -- the problem is not to affect output. This requires extensive knowledge of the location and shape of the supply curve for both established production and new reserves. Moreover, if the reduced prices (increased real incomes) bring about an increase in the quantity demanded, then there will be excess demand even if supply is not affected by the differential regulatory scheme, and some technique will have to be developed for limiting this demand to the previously established level.

Neither the Federal Power Commission nor the Courts have clearly distinguished the two separate regulatory objectives -- controlling market power and transferring rents to consumers -- and they often write as if they were trying to achieve both of

them at once. In the past few years, however, the Commission has indicated that the second objective is its predominant concern. For one thing, the Federal Power Commission and several Courts have expressed a belief, or fear, that efforts to limit price have reduced the supply of new reserves and will soon lessen the actual levels of gas production. Lowering prices from "monopoly" to competitive levels should have had the exact opposite effect -- should have increased both reserves and production. The Federal Power Commission's continued efforts to regulate suggest that it no longer sees itself as basically trying to control monopoly power. For another thing, economists for the distributing companies (upon whom the Commission has closely relied) have most often rested their case on a belief that the supply of gas is inelastic -- that the percentage reduction in quantity supplied is substantially less than any given reduction in prices as a result of regulation. As a result of this state of affairs, the "shortage problem" has been thought to be of minor practical importance compared to the "income distribution problem".[30]

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[30] Although this may be a practical consideration, it is not satisfactory logically. The acknowledgement of a shortage places the analyst in the position of comparing the gains of those who receive gas at a lower price against the losses of those who experience the shortage. It is not sufficient to measure these in physical quantity terms, but rather to show that the losses in utility or satisfaction from consumption, as measured in "willingness to pay", are less than the gains in the utility or satisfaction from consumption of those who experience this "consumers' windfall". This comparison has not been made by proponents of ceiling price regulation; indications below do suggest, however, that the net gains must be negative.

For a third thing, the Federal Power Commission itself has set two price levels as a result of the area rate proceedings -- higher prices on "new" gas, and lower prices on "old" gas. The development of this procedure, along with expressions of concern that the new gas price is high enough to cover the costs of producing marginal supplies, suggests that limiting producer rents and windfalls has been an important concern underlying regulation.

Overall, however, our impression from the Commission and Court decisions is that the two reasons for regulation are used interchangeably or wherever one or the other of them fits more conveniently. This way of doing business is not tenable -- one cannot assume the lack of competition, and the presence of some of its windfall benefits, all at the same time. Attention has to be centered on one or the other. In view of the lack of empirical support for the notion that producers possess monopoly power, we shall assume that limiting the market power of gas producers is not a sensible regulatory goal to pursue. It seems more reasonable -- because it corresponds more closely to the facts of gas industry life -- to try to limit producer rents and windfalls. We shall assume that this is what the Commission has been trying to do, and will examine the methods that it has used to do it. Then we will assess the effects of producer regulation to this point in time.

Alternative Methods of Regulating Field Prices

The Federal Power Commission first tried to regulate gas producers as if they were public utilities allowed to earn "fair return on fair value". The procedure, used in setting prices or rates for telephone companies, electricity distributors, and gas pipelines, is to find the cost of service for supplying the amount of a product that the utility is likely to sell; the Commission allows prices or rates sufficient for the company to recover these costs but no more (where the costs include a specified percentage rate of return on the original cost of undepreciated capital equipment).[31] This approach might seem to offer several advantages over other ways of regulating natural gas producers. It seems to promise that no producing company will earn more than a reasonable return on its capital -- or at least all companies are likely

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[31] The more mechanical but detailed steps of the procedure would be as follows: (1) the regulated firm offers to provide a volume of service Q_t for costs per unit of service C_t [which is by implication the regulation price P_t]. Costs are broken down among (2) the total variable costs for labor, raw material input such as natural gas in a transmission line, and any purchased goods and services from other companies. Total variable expenses V_t are used to estimate unit variable costs V_t/Q_t. The producer also estimates (3) depreciation charges on capital equipment D_t and unit depreciation charges D_t/Q_t, but also (4) the required profits equal to the rate of return r multiplied by the undepreciated original cost of capital equipment or $K_0 - \Sigma D_t$ (known as the rate base). The regulatory commission either accepts this calculation of costs and sets $P_t = V_t/Q_t + D_t/Q_t + r(K_0 - \Sigma D_t)/Q_t$ or else the Commission makes alternative estimates of one of these factors in the calculation.

to earn approximately the same rates of return, so that those who would receive windfalls have to pass them on as lower prices. This approach would also seem to make it possible to avoid serious shortages. If cost were to increase, and there were demand for the higher cost (and higher priced) reserves, then regulation would not interfere. On the other hand, this method does not provide ways of allocating the gas produced -- that is, ways to determine who should get the more expensive gas, and who should receive the cheaper supplies. Also, the method assumes that substantive information is available on elements of cost in great detail. It must be expected that costs on new additions to reserves can be determined as accurately as can the costs of gas transporters, electricity generating companies and telephone companies.

As the Federal Power Commission found out, however, the problems of determining the cost of gas production -- and thereby applying cost of service regulation -- can be far more serious than those encountered in traditional public utilities. Finding the cost of natural gas poses several extraordinary -- probably insurmountable -- difficulties. The first problem arises from gas being produced in many cases in conjunction with oil. Expenditures on exploration in particular yield joint production of petroleum and natural gas -- some oil wells, some gas wells, and some joint wells in addition to many dry holes.

Expenditures on development yield gas with liquids of a number of types, and expenditures on refining yield both "dry" gas and liquids that can be sold. Expenditures such as these which yield two products, but which are necessary in order to produce either product, complicate the regulatory process because there is no direct way to decide whether, or to what extent, a specific dollar outlay should be considered to be the "cost of gas production", or part of the "cost of liquid production".

The problem is distinctly a regulatory problem. Without price controls, under competitive conditions, producers would recover joint costs from the sale of gas and from the sale of oil, but the relative amounts recouped from each will vary from firm to firm and over time. With price controls of both oil and gas, the regulator could reproduce competitive market decision rules, by requiring that the combined revenues from the sale of the two equal the combined costs. The company could propose prices that would cover total costs, securing revenues from either of the two sources as it chose. In fact, this procedure is followed generally in regulation of electricity distribution, telephone services, and other public utility services, and the problems of joint costs are overcome at least in part. The distinctly serious regulatory problem for gas is that oil prices are not regulated by the Federal Power Commission.

Therefore the Commission has to find the "exact" costs of one of the joint products because to do otherwise would be to rely on the earnings in an unregulated sector, or to actually control these earnings on unregulated petroleum outputs as if they were regulated.[32]

The Commission has struggled with the problem with no success. Attempts have been made to apply various traditional accounting techniques for allocating joint costs. One method has allocated costs on the basis of the ratio of single product oil production to single product gas production costs. A second method attempts to allocate joint costs in accordance

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[32] Consider the following procedure. The Commission requires that the companies submit prices that cover the cost of producing gas, including (1) the separate costs of gas extraction plus (2) joint costs only insofar as they are not covered by revenues received from the sale of petroleum. For every dollar less that it earned from oil sales, the company would be allowed to earn a dollar more from gas sales. Such a system has obvious drawbacks. First, it requires information on petroleum sales of the sort that is required of regulated sales, when petroleum is not regulated. To ask the company to provide estimates of future oil prices may be to ask for exceptionally costly and uncertain information. Second, the Commission would have to regulate the price of oil eventually, in order to prevent the producers from reducing it to marginal costs. A producer earning rents on oil sales knows that if he raises his oil price one dollar, he will simply have to reduce his gas price one dollar -- as long as joint revenues cover total costs, he has no incentive to increase one price or the other, except to maximize the size of total sales. That particular combination which does maximize sales conceivably includes a competitive price for oil and a regulated but monopoly price for gas (as long as the profits are at a control level on the two products together).

with the number of BTU's contained in the oil as a ratio of the number of BTU's contained in the gas produced. A third method has recognized that a BTU of oil and one of gas may not be of equal value (because of pollution or other effects specific to one of the fuels). This method requires that the BTU's be multiplied by a factor representing relative value, or that costs are determined in part as a ratio of prices (a suspicious method because these costs are used to determine relative prices under regulation). All three procedures share the vice of having little relevance to the price that gas would command under competitive conditions. Rather, they bear out Justice Jackson's view, when he wrote, "to let rate base figures compiled on any of the conventional theories of rate-making govern a rate for natural gas seems to me little better than to draw figures out of a hat." These techniques do not find long term marginal cost of a single product (when the products can be produced in variable proportions). Worst of all, they create the illusion of separable costs when these costs are truly joint and cannot be separated (when outputs are produced in fixed proportion).[33]

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[33] The Commission failure here has not been crippling, because the problem has not been of a first order of importance. Since the middle 1950's, the number of joint wells has diminished to the point where gas output from them accounts for about 25% of total gas production. And it has been strongly argued that exploration is "directional" -- that gas and oil can be searched for separately and usually one is not found as a result of a search for the other. Insofar as producers act on this belief, exploration expenditures are not joint and can be fairly allocated in accordance with the one product they yield. Nonetheless, joint expenditures are still sufficiently important to make a pricing system that allocates them via these accounting methods an exercise in the arbitrary.

The Commission struggled with two more serious problems in finding costs for each company. The first problem was the usual one of determining the proper rate of return, but it was of more than usual magnitude for natural gas producers. The general approach was to carry out a historical review of returns, with references to whether these appeared to be absolutely "high" or "low" and to the returns earned by firms in other industries where "risks were comparable". But no process presented itself for choosing the comparable industries. It has been widely acknowledged that gas production is more risky than running a telephone company, but perhaps not more than operating a petroleum or a steel company. Even if a method were found for choosing comparable companies, it has not been a straightforward matter to compare costs of capital. Comparable costs of debt have not been found because most gas producers have little debt (less than 15 percent on average). Equity returns have not been directly comparable because the shares of small gas companies have been rarely traded, and those of large gas companies have been rendered incomparable by the fact that many produce both gas and petroleum. The whole process was rendered impractical by the necessity to make these calculations for thousands of different producers.

The vast numbers of producers of natural gas created overwhelming difficulties for rate of return regulation. In

1954 there were 4,500 producers or more, and by 1960 they had submitted more than 2,900 applications for increased rates that had been suspended without action. The individual producer cases would require a finding on the joint costs attributable to gas, on the required rate of return and rate base, for each of the dozens of companies involved in each of the 2,900 suspended applications. This would have taken an interminable period. The decision in Phillips Petroleum Company itself required 82 hearing days, and testimony of 10,626 pages with 235 exhibits. Although further cases might have been handled in shorter time with less legal material, differences from case to case in joint costs and degrees of riskiness, and therefore in allowable rate of return, were such as to require individual decisions in each case. By 1960, the Federal Power Commission had completed only ten of the thousands of these cases. The delay in the remaining cases led the Landis Commission, appointed by President Kennedy to study the regulatory agencies, to conclude that "without question, the Federal Power Commission represents the outstanding example of breakdown of the administrative process."[34] Management failure alone could account for the need to abandon producer regulation on an individual rate of return formula.

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[34] James M. Landis, Report on the Regulatory Agencies to the President-Elect (reprinted by the U.S. Senate, Committee on the Judiciary, Government Printing Office, Washington, D.C., 1960), pp. 5-6.

Even if the number of employees had been drastically expanded -- four or five-fold -- the Federal Power Commission probably would not have been able to continue with this type of regulation. The theoretical problems involved in finding separable marginal costs, and the proper rate of return on capital, were exceedingly difficult and important. These problems are found in seeking to regulate individual companies in any competitive market, and they demonstrate themselves by showing "proper regulated prices" for the same product at the same location which depart from each other in a significant and arbitrary way. The cost of conducting regulation cannot be justified by these arbitrary solutions.

Since 1960, the Federal Power Commission has embarked on a policy of setting producer prices in batches, dividing the country into five producing areas and determining price ceilings for "old" gas and separately for "new" gas in each area. In each of the two proceedings completed to date, the Commission has set a higher price ceiling for gas from newly discovered gas wells, and a lower ceiling for gas from old gas wells or from joint oil-gas wells. The motivation for two prices would seem to be to transfer rents from producers to consumers -- there is no basis for arguing that producers of "old" gas have more monopoly power than producers of "new" gas. The goal was to complete this transfer without unduly restricting

the amount of gas supply. It is clear that there would be some restriction, since the lower price on old gas would increase the quantity demanded without changing the amount supplied.

The hope for two-tier prices may well have been translated into a fear of significant shortages of natural gas. The shortages could follow from three practical defects of the ceiling price system. The first is the lack of a regulatory mechanism for rationing the excess demands that would occur from setting prices at the marginal cost for both old and new reserves. Even if new prices were equal to the long run marginal costs of new reserves, which is the competitive norm, then the old reserve prices would be less so that some sales would have to take place at below the market clearing price level. There has to be a rationing mechanism to supplant the market clearing mechanism so as to curtail the excess demands induced by the lower prices. This may be the least of the concerns -- for the two prices themselves may be set below the long term marginal cost of both old and new reserves. This mistake, conceivable under regulation if not under market clearing competition, would cause a serious misallocation of resources -- particularly if the "rationing mechanism" is not a regulatory procedure but a first-come, first-serve way of doing business. Under these circumstances, those who receive the gas would as

likely be marginal purchasers brought into the market by the artificially reduced prices as those with the most intensive demands.

That such harm is far from theoretical is suggested by the fact that the Commission can regulate producers' interstate sales but cannot regulate the price at which they sell gas intrastate. Thus in times of shortage, they may sell far more gas intrastate where prices are allowed to rise, and sales are made to industrial purchasers on a margin of choice between petroleum, natural gas, and other sources of hydrocarbons. The gas that they purchase is diverted from interstate residential and commercial users willing but unable to pay a much higher price (because of their lack of alternative sources of clean heating energy).

How likely is it that the Commission would in fact induce the maximum shortage by setting new gas prices below the long term costs of exploration and development? An examination of the methods used by the Commission to set new gas prices -- and for that matter alternative possible methods considered by them -- suggest that the answer must be "highly likely". The first method used by the Commission to find a ceiling price for new gas was to determine and set that price equal to the average cost of developing recent additions to reserves. Thus, in the Permian Basin case, the Commission staff surveyed both major

and minor producers to discover their production costs for the base year of 1960. Experts employed by the producers, and some employed by distributors, did similar surveys, and together they produced a range of estimates of average exploration and development costs. In the Southern Louisiana case, these analyses were undertaken once again for the base year 1963. After considerable dispute on the validity of some of the estimates, the Commission used those considered most accurate and complete to set new gas price ceilings in both cases.[35] These prices in both cases turned out to be roughly equal to the interim prices set in the early 1960's for these regions.

The similarity of the final ceiling prices to the provisional prices is not at all surprising given the method. This is because the provisional price ceilings themselves biased any effort to obtain the cost of new production. Since producers knew that they were unlikely to be able to sell gas at more than these prices, they developed those reserves having lower costs. Rates of addition to new reserves and to recent production were set so that marginal costs did not exceed the interim ceiling prices, and this must have resulted in the average costs of new reserves (excluding any extraordinary

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[35] The average costs were increased to provide an incentive to produce more gas to meet growing demands, however.

economic rental payments) being slightly below the interim ceilings. If the Federal Power Commission had set provisional prices at one cent per Mcf, it would have discovered in retrospect that the average costs of new gas production would have been slightly less than one cent, for no gas that had higher marginal development costs would have been offered for new reserve contracts. The use of historical average costs to set ceiling prices was then equivalent to freezing prices at the level experienced in unregulated markets in the late 1950's, since average costs were set by historical prices which then set new prices.

The problem was that the Commission failed to inquire about the marginal cost of additional reserves at _market clearing quantities of these reserves_, and instead inquired only about average costs at _previous historical levels of output_.

A further problem, compounding the error of a price freeze, arose from trying to discover average costs rather than marginal costs. If the Commission were not to discourage new production, it should have been certain that the ceiling was higher than marginal development and extraction costs. With a wasting resource from a fixed stock of uncertain size, the marginal cost must be greater than the average cost.[36] The higher cost producers include not only the unlucky or less

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[36] Cf. Paul F. Bradley, _The Costs of Petroleum_ (North Holland Publishing Company, 1968).

skillful, but also those forced to search farther afield, or farther underground for gas, having exhausted their prospects on promising lease holds. If this is the case, averaging their costs in with the new gas costs of fortunate or unusually skillful producers understates the likely costs of further new gas production. Setting ceiling prices on the basis of average costs guaranteed that the exploration and development of the sought-for level of reserves would not take place, because these prices would be less than the marginal costs of achieving that volume of additional reserves.

The Commission and its examiners tried to account for these problems by adding to the average historical costs of finding new gas an "allowance for growth". In the Permian Basin proceedings, for example, it added 1.11 cents per Mcf to the ceiling price in recognition that producing enough new gas in the future to meet growing demands would probably require the exploitation of more expensive reserve sources. But the determination of this particular premium was an obscure process. This estimate of the "proper allowance" was presented by an expert appearing for the gas distributing companies as a judgmental observation (strongly disputed by experts for the gas producing companies who in turn concluded judgmentally that the proper figure was 2.15 cents per Mcf). The proper premium would take into account increases in exploration costs, changes

in the probability of finding gas through exploration, and possible changes in the required rate of return for attracting speculative capital into gas production. The estimates for these categories of costs are highly speculative, yet because they account for such a high proportion of total gas costs -- 60 percent or more -- they make the task of determination absolutely critical for finding the proper level of new gas prices. Again, this may have been an attempt to accomplish the impossible, and to leave the accomplishment to expert witnesses for the gas distributing companies seeking to produce a price freeze.

Faced with the extraordinary difficulty, and the very large chance of error, in determining the costs of "new" gas at the market clearing level of reserves and production, the Federal Power Commission has more recently turned to a process of direct negotiation on prices. In the Southern Louisiana case, representatives of the producers, distributors, and other customers bargained out a "settlement" which most of them then presented to the Commission for approval. The Commission and the Courts took the negotiation under advisement along with a great deal of information on costs, and made a decision to set price ceilings slightly below the proposed settlement figures. When the gas shortage in the late 1960's led the Commission to reopen the Southern Louisiana proceedings, once again the

parties negotiated a settlement. This time the Federal Power Commission adopted the settlement figures as its own, holding that they constituted reasonable ceiling prices.[37]

The setting of ceiling prices by negotiation must be an admission of bankruptcy in both reasons for regulation, and in ability to analyze the results. Negotiation among interested parties to "settle" a Federal Power Commission proceeding scarcely can be conceived of as control of monopoly power, since it bears no resemblance whatsoever to the bargaining over price among buyers and sellers in a competitive and open market. For one thing, the parties bargain in blocks -- the buyers together in one block bargaining with a group of producers. The price may end up higher than, lower than, or equal to that which would be set in a competitive market depending on the skill and power of particular bargainers. More important still, the parties are constrained by their knowledge that the Federal Power Commission and the Courts must approve the result, so that any price out of line with past prices or any price that departs too radically from average new gas costs would not likely be approved.[38] The other possible reason for

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[37] U.S. Federal Power Commission, Opinion and Order Determining Just and Reasonable Rates for Natural Gas Produced in the Southern Louisiana Area, Dockets #AR 61-2, et al., #AR 69-1, Opinion #598 (July 16, 1971).

[38] Thus, it is not surprising that the first negotiation in the Southern Louisiana case produced a settlement very close to the provisional guidelines for that area. Yet, once the Federal Power Commission reopened the proceeding, indicating that it expected to raise prices to alleviate the national gas shortage, renegotiation produced a settlement price 20-25% higher than previous negotiated prices.

regulation -- control of windfall gains and rents -- does not support the negotiated price process either. If the object of negotiation were to achieve accuracy -- to avoid the risk of setting the ceiling too low so as to cause a shortage, or too high so that the ceiling had no effect on actual transactions -- then the argument establishing this increased accuracy has yet to be developed. There is no reason to think that negotiation would improve to any great extent upon cost investigation.

The undeniable advantage to regulation by "negotiation" would be its administrative simplicity. The price ceiling that would emerge from negotiation would very much be the result of chance. But the Commission might be able to reduce its workload, and prevent conflict and litigation between buyers on the one side and sellers on the other, by making them agree before the case review begins. Except for the overlay of previous Commission decisions, which establish that price will not change very greatly, this is the same as if regulation of field prices were being abandoned entirely.

The Regulation-Induced Shortage of Natural Gas

The economic problem with field price regulation is that there seems to be no way to set a ceiling on new reserve prices

without causing some amount of excess demand. The excess may not be small, however, because there seems to be no way to set the ceiling without running serious risks of going below the marginal cost for new reserve development. The latter problem may provide strong inducements to decrease the quantity supplied, as well as increase the quantity demanded, so as to create a large shortage of gas.

How serious have these problems turned out to be in the last decade? Some have argued that gas supply responds so slightly to a price increase or decrease that even if prices were set too low, there would be a small amount of supply reduction as a consequence. The contrary assertion is that both supply and demand are highly elastic, so that moving below the market clearing competitive price level, even on sales of old reserves, will bring about a substantial artificial increase in demand and create substantial excess demand. Which view is correct is an empirical matter.

In the last few years there have been a number of indications of a serious shortage of natural gas reserves. Some have been statements by industry experts on new evidence of a shortage, or on what ought to be done. Many declarations on the subject have stated that the F.P.C. "area rates" have been an important cause for the supply-demand difference and that new area rate policies are needed to reduce the excess demand.

The sources of these statements have been so diverse as to suggest a consensus. Not only producers but also buyers have claimed that there was substantial regulation-induced excess demand and that ceiling prices under new contracts were too low. The buyers in the midwest and on the eastern seaboard regions have experienced such a shortage of new field reserves that they have had to announce restrictions on sales to new customers in Chicago, New Jersey and Pennsylvania. One of the pipelines into the New York metropolitan region has had to reduce winter deliveries by 8 percent -- when demand has been increasing drastically (because of local pollution regulations). The Chairman of the Columbia Gas System (transmission) recently announced that this company would limit its new sales commitments, "because customers have recently made requests for next winter far exceeding [previous] requirements.... we cannot obtain the additional gas to meet these demands." Chairman Loomis laid the shortage to "unrealistic area pricing policies on gas production," combined with unforeseen increases in demand.[39] The testimony of M. D. Borger, Chief Executive Officer of Consolifated Natural Gas Company (Pittsburgh), in the Southern Louisiana Area Rate Proceeding, described that company's 1967-1970 attempts to secure more gas for retail delivery as

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[39] "Columbia Gas will limit new commitments to sell natural gas; short supply cited," Wall Street Journal, April 10, 1970, at p. 34, column 1.

unsuccessful: "we were unable to contract with our [pipeline] suppliers for any additional long term supplies.... we were routinely met with the response that there was a shortage of gas for purchase in the gas fields in Texas, Louisiana and the midcontinent areas of the United States."[40] His own investigations led to "my own conclusion now ... that the volumes of undedicated reserves which may be available for purchase by the pipelines are insufficient to meet current increases in utility demand.... in large part because of the cumulative effects of regulation under the Natural Gas Act during the period since the Phillips decision in 1954. In my opinion, price reductions and price rollbacks and instability have stifled exploration operations while the resulting low rates have created an artificially-high demand for natural gas."[41] Other distributors and some of the state regulatory commissions have disagreed with these reasons for some of the local gas shortages, but the statements of Columbia and Consolidated represent a new and strong trend of policy views. This policy of buyers would be to raise the prices they pay. The pipelines to the North and East have found the regulated prices below what they would be willing to pay for additional production

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[40] Testimony of M. D. Borger, before the Federal Power Commission, Docket #AR 69-1, at 5,6.

[41] Ibid., at 8, 10.

rather than go without, and they have joined the producers in seeking higher prices.

The F.P.C. has also acknowledged the existence of a substantial shortage. The staff dealing with natural gas regulation has issued reports in recent years showing that additions to gas reserves of the pipelines have been insufficient to meet "market requirements for extended periods of time."[42] Most recently, the staff concluded that the pipelines could have met the demands existing in 1963 for fifteen years thereafter, while they could meet 1968 demands for no more than seven years.[43] The staff view has been shared by the Commission, at least to the point of recognizing that ceiling prices have been far too low to clear gas field markets. In the opinion issued on rehearing of Southern Louisiana Area Rates, the Commission concluded that "the vital importance of future additional gas supply from offshore warrants...further proceedings...looking towards a possible revision of the area rate proceedings for such gas."[44] And to some extent a

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[42] The Federal Power Commission, U.S. Bureau of Natural Gas, Gas Supplies of Interstate Natural Gas Pipeline Companies 1968 (1970), at 14.

[43] Assuming in idem (Gas Supplies) at 15, chart 3, that two trillion cubic feet of "normal replacement" reserves are forthcoming from extensions and revisions of present fields.

[44] Southern Louisiana Area Rate Proceedings, op. cit., Opinion # 546-A.

Commission's policy reflects the views of the Chairman. The Chairman of the F.P.C. has recently taken a stance on a national policy issue outside F.P.C. jurisdiction on the basis of the "natural gas shortage" alone. Because supplies of new gas reserves have been short, Chairman Nassikas urged that oil import quotas be maintained to provide every possible incentive for finding gas in the quota-induced search for domestic oil.[45] This position would seem to imply that prices of oil should be kept too high because F.P.C.-regulated prices of gas are too low. Also, it is very likely inexpedient policy within interrelated markets for energy sources, since higher prices for oil increase the demand for gas as a substitute boiler fuel, adding to excess demand. The Nassikas view can be rationalized only as emergency policy, given that the shortage of gas is acute.

These expressions of opinion lead to the conclusion that a natural gas shortage exists, partly at least as a result of regulated prices having been set too low to clear field markets of increased demands. They do not show the magnitude of shortage, nor the effects on different consumer groups. The sources

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[45] Cf. Supplementary views of the Chairman, F.P.C.; Impact on the Natural Gas and Electric Utility Industries, in Separate Report on the Oil Import Question by the Secretary of the Interior, the Secretary of Commerce, and the Chairman of the F.P.C., in U.S. Cabinet Task Force on Oil Import Control, The Oil Import Question, A Report on the Relationship of Oil Imports to the National Security, 369 et seq. (1970).

of excess demand are as important as the magnitude, because those doing without might be especially disadvantaged in using substitute fuels. Yet the F.P.C. staff reports show only measures of deficiency, and these are based on "requirements" rather than price-related demands, so that the effects of the ceilings have not been shown.

The size and source of excess demands will be assessed here. First, the size of the shortage in the last few years is estimated by recourse to an inventory analysis, in which the inflow of newly discovered gas reserves is put against new production. The critical element is the judgment on the amount of reserves "required" to provide assurance of continued supply to a new customer. If this backing should be as extensive as that for new deliveries in the 1950's, then more than one-half again as much reserves should have been available in the last five years. If the backing had to be twenty years' production, then one and one-fifth again as much new reserves should have been committed to the pipelines. This is the shortage. Subsequent paragraphs attempt to assess the role played by the price ceiling in the shortage. The measures are from an econometric model of gas supply and demand constructed on the basis of market clearing conditions in the 1950's, but then used to simulate behavior "without regulation" by extrapolation of these conditions to the 1960's. The simulations of newly

discovered reserves and prices are compared with actual new reserves and prices under area rate regulation and the differences are attributed to regulation. They show reserves to be substantially less than if prices had been higher -- and the higher prices would have cleared markets by increasing supply and reducing demand proportionately. The last paragraphs in this section look at who has received gas in these shortage markets --. the home consumer at regulated resale prices or the industrial user at unregulated prices. Regulation seems to have played a large role in this decision also, and as a consequence the home consumer does not seem to have done very well.

An "inventory approach" to excess demand. The field markets for natural gas are not similar to those for other fuels because there are no large volume spot transactions for the purchase and delivery of gas at one location in one day. Rather, reserves of gas are dedicated to pipeline buyers, and these reserves are depleted by production into pipelines over an extended period of time. The dedications are sales by contract which specify initial prices, delivery period, and the property rights to in-ground gas reserves. The contract markets can be said to clear if the amount of newly-dedicated reserves meets the inventory requirements for new production going by pipeline to final industrial and home consumers.

These inventory needs certainly exceed the amount actually produced under a new contract in the first year of that contract. Pipelines generally do not make connections for a single year's deliveries, nor sign 10 to 20 year contracts for delivery without reserve backing. The question is how much backing is optimal, given that more reserves provide more certainty for the pipeline against default on its promised deliveries, but also more reserves require greater pipeline expenditures.[46] To some extent, the regulatory process provides the answer: the F.P.C. has considered the proper amount of reserves to be twenty times initial production, so that (regulated) demands for new reserves are based on "the assumption that each new market commitment is backed by a twenty year supply."[47] But the average buyer -- pipeline and non-pipeline -- has sought less extensive security than that recommended (but not required) by the Commission. Additional reserves ΔR_t have been added by all buyers on average each year since 1947 -- about the time interstate delivery began on a large scale -- equivalent to 14.5 years of additional deliveries

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[46] In theory, at least, a longer waiting period for production imposes higher costs on the supplier, necessitating higher contract prices to the pipelines. This cost increase was not reflected in significantly higher prices on longer term contracts, however, during the period just before area rate regulation. Cf. P. MacAvoy, Price Formation in Natural Gas Fields, op. cit., pp. 262-265.

[47] Federal Power Commission, A Staff Report on Gas Supply and Demand 18 (1969). Twenty years reserve "backing" is equivalent to twelve years "deliverability"-- that is, twelve years production at all field capacities.

ΔQ_t each year. For national reserves and production, $\Delta R_t/\Delta Q_t = \alpha + \beta T$ has been $\Delta R_t/nQ_t = 13.5 + 1.0T$ ($R^2 = .21$) with T = 1 to T = 11 for the years 1947-1957,[48] or 14.5 years reserve backing at the beginning of the period, and 24.5 years at the end. The inference might be that it was optimal over the early 1950's for most buyers to keep less reserve backing than recommended under regulation.

The demand for new reserves by interstate pipelines in the 1960's, under field regulation, might have continued to be based on these "backing rules." Applying the rate $\Delta R_t/\Delta Q_t$ given by ($\alpha + \beta T$) to actual production on new contracts nQ results in an estimate D_1 of the "expansion demands" for new reserves, where these demands would be in keeping with continued 1947 national patterns. Alternatively, twenty years backing could have been sought as one of the guarantees of the "public interest" protected by the F.P.C. Applying the twenty-year ratio to nQ

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[48] The production and reserves series are from 23 American Gas Association, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United Stated and Canada as of December 31, 1968 (1969). In order to find additional reserves dedicated to additional production, the year-to-year changes in reserves are calculated first. These equal ($R_t - R_{t-1} + Q_t$). Second, an amount Q_{47} is subtracted, given that this equals the required replacement for existing 1947 commitments that have not cancelled. Then $\Delta R_t = (R_t - R_{t-1}) + (Q_t - Q_{47})$. The line $\Delta R_t/\Delta Q_t = 13.5+1.0T$ was fitted to the 11 observations by the method of "least squares"--so as to minimize the sum of the squares of the deviations of the observations from the line. This procedure has widely-recognized characteristics, such as yielding the statistic R^2 (showing the percent of variance in $\Delta R_t/\Delta Q_t$ explained by the fitted line), and will be used extensively below.

results in the "Commission-approved" reserve backing for new demands -- that which would provide the backing sought by the regulator for the level of security deemed "necessary" for final consumers. Both are hypothetical because they could not have been realized under the shortage.

At the same time that pipelines seek reserves for expansion, they demand new reserves to replace amounts depleted by completion of earlier contracts. These replacements could not be expected to be complete. A number of old contracts would not likely have been continued because prices for replacement gas were greater than the original prices; the buyers taking gas at the earlier prices were changing to oil or coal. Replacement demand D_2 would equal $\gamma Q_t(\alpha + \beta T)$ where γ is the proportion of established deliveries Q_t which were depleted and were going to be replenished. Alternatively, $D_2 = 20\ \gamma\ Q_t$ for the "Commission-desired" twenty-year reserve backing.

Total new reserve demands $D_1 + D_2 = (nQ_t + \gamma Q_t)(\alpha + \beta T)$ in any year [or $20(nQ_t + \gamma Q_t)$ at the Commission-approved inventory level]. Finding what these demands were requires estimates of nQ, the amount of deliveries to new customers in the first year, and γ, the proportion of established deliveries to be replenished; but both require detailed studies of sales contracts. and of the elasticities of demand of old and new customers, that are not possible given present data conditions. It is possible

to estimate the total $(nQ + \gamma Q_t)$ directly, however, because $(nQ + \gamma Q_t) = (Q_t - Q_{t-1}) + (\gamma + \varepsilon)Q_t$, where $(\gamma + \varepsilon)$ is the rate of depletion of reserves, γ is replacement, and ε is non-replacement, since additional production takes place only for either expansion or replacement purposes. Production under new contracts $(nQ + \gamma Q_t)$ by definition must either expand production $(Q_t - Q_{t-1})$ or replace depleted production $(\gamma + \varepsilon)Q_t$.[49] Estimation is confined to finding $(Q_t - Q_{t-1})$ the year-to-year change in the total, and $(\gamma + \varepsilon)$, the proportion of any year's production that depletes reserve holdings.

The estimates of production, and the reserve backing sought by the pipelines, are shown in Table 1. For new production, the value of $(\gamma + \varepsilon)$ in each year was taken to be $1/(\alpha + \beta T)$ for $T = 1$ for 1947,[50] and the rates Q_t, Q_{t-1} were as shown in the F.P.C. Staff Study The Gas Supplies of Interstate Pipelines (1968). To find the required reserves, the new production $[Q_t - Q_{t-1} + (\gamma + \varepsilon)Q_t]$ was either multiplied by $(\alpha + \beta T)$, the trend of preregulation marginal reserve-production

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[49] Here $(\gamma+\varepsilon)$ is the proportion of previous years' production which depletes reserves, γ is that proportion which is replaced by new contracts written with the same established customers, and ε is that proportion not replaced by new contracts.

[50] This is the rate of depletion of new national reserves in 1947. It is taken to be representative of depletion of old interstate pipeline reserves in 1964-1968 because the period of large scale development of the interstate lines began approximately in 1947 and the initial reserves were probably being depleted at this rate.

Table 3

ESTIMATES OF SUPPLY AND DEMAND FOR RESERVES

Year	"Company" reserve demand: continuation of previous national average reserve accumulation (1)	"Regulated" reserve demand: 20 years reserve lifetime (2)	Supply: additions to reserves (3)
1964	[0.7+.07(9.6)][14.5]=19.8	27.4	10.7
1965	[0.2+.07(10.3)][14.5]=13.2	18.4	12.8
1966	[0.8+.07(10.5)][14.5]=22.1	30.7	14.9
1967	[0.7+.07(11.3)][14.5]=21.4	29.8	15.7
1968	[0.8+.07(12.0)][14.5]=23.6	32.8	9.4

Source: U.S. F.P.C., The Gas Supplies of Interstate Pipelines (1968).

"Additions to reserves" are $(R_t - R_{t-1}) + Q_t$, as shown by pipeline company responses to F.P.C. Form 15 and 15A.

"Company" reserve demand is $[(Q_t - Q_{t-1}) + (\gamma+\varepsilon)Q_t](\alpha+\beta T)$, as explained in the text. Here $(\gamma+\varepsilon) = (\alpha+\beta T)^{-1}$.

"Regulated" reserve demand is $[(Q_t - Q_{t-1}) + (\gamma+\varepsilon)Q_t]20$, in keeping with the Commission-expected twenty-year reserve backing.

All statistics are in trillions of cubic feet.

ratios, or by the "twenty times production" factor of the F.P.C. On these bases, the amount of new production ranged from 0.9 trillion to more than 1.6 trillion cu. ft. in one year, and the

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demanded reserve backing for the new production from the "pre-regulation level" of 20 trillion to a Commission-required 33 trillion cu. ft. in one year. The supply of new reserves, as shown by the pipeline companies' actual contract volumes, was less than the reserve backing demanded over the years 1964-1968. The demands for pre-regulation backing in column (1) were 156 percent of the actual volumes of new reserves committed under contracts signed in 1963-1968. The "twenty times production" reserve backing in column (2) was not secured -- these cumulative "Commission" demands were 219 percent of new contract commitments. Excess demand must have been from one-half again, to one and one-fifth again, as much as the actual new contract reserves committed in the late 1960's.

The shortage almost certainly has been realized in the elimination of security of delivery for final buyers of natural gas. The F.P.C. ceiling prices may have caused this five-year shortage, but this is not apparent from a review of inflows and outflows of gas reserve holdings. The approach to be taken in order to infer the effects of field price regulation is to find the approximate market prices and quantities for conditions similar to those when markets cleared in the 1950's and then compare these with regulated ceiling prices and quantities. It is suspected that the market clearing prices would have been higher, and would have brought forth a greater supply of reserves

from new discoveries. Any remaining supply-demand difference might well have been eliminated by price-induced substitution of other fuels for gas.

A supply-demand analysis. In the absence of area rates there would have been significant increases in prices in new gas contracts, and there might well have been significantly greater new reserve commitments during the 1960's. General increases in demands for energy, during a period in which the supply responses in coal and oil markets were less than might have been expected, should have led to short term price increases for new gas reserves. The gas supply response might have been substantial -- enough to fill in a major part of the excess demand shown in Table 3. The method for showing market-clearing is first to find supply and demand schedules characterizing behavior in the 1950's, and the market-clearing prices in that period. Here supply and demand models are constructed and used to determine ΔR_{tj} (reserves added in year t in producing district j) and P_{tj} (the average of the initial base prices on new contracts signed in year t in producing district j) for the years 1955 though 1960 in two markets, gas for the East Coast and Mid-West (EMW) and gas for the West Coast (W). The model values for ΔR^*_{tj}, P^*_{tj} are the market-clearing values since they solve the supply-demand system fitted for the 1950's; even though they differ from the actual values, these differences

are small from year to year, so that it would appear that markets cleared in the 1950's. The second step is to apply the model to the 1960's, by inserting 1961-1967 values for the "outside variables" into the supply and demand schedules and then solving the system for market-clearing values ΔR_{tj}^{*}, P_{tj}^{*}. The model values are compared to the actual reserves and prices, and the differences attributed to the lack of adjustment in the (regulatory ceiling) prices.

An "inelastic" supply model takes a very specific view on the exact nature of the process of finding and developing new gas reserves. This "engineering" view -- one that implies the smallest possible effects from price ceilings -- is based on the belief that gas reserves are discovered incidentally in searching for oil, and then made ready for development by rapid drilling programs designed to prevent "capture" by adjoining developers. Reserves ΔR_{tj} added in any gas supply district are greater when total expenditures, C_{tj}, on drilling are greater,[51] or $\Delta R_{tj} = f_1(C_{tj})$. This view will be tested, not because of compelling factual content, but because its implications include that of no direct effect on discoveries from price ceilings. With complete information on oil exploration, resulting new gas

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[51] This last argument is the reversal of the commonplace marginal cost argument: for $C = f(Q,A)$ then $\partial C/\partial Q > 0$ for C total costs. Here, $\partial Q/\partial C > 0$ in $Q = f(C)$.

discoveries, and development costs, this argument could be tested; here, a modified version has to be used because of very incomplete information.

The indications of discoveries are not statistics on reserves in new gas fields resulting from recent drilling operations, and offered for contract sales, but rather direct statistics on the amount of gas recorded as discovered in that district and that year, whether ready for sale or not. The discovery estimates are thus for new volumes in place. Oil and gas discovery operations are continuous and what is found in a district depends on what was found there the year before; as a result, the most concrete determinant of what is found and the amount available for use is the previous year's reserve discoveries in that district. The analysis should be modified so that $\Delta R_{tj} = f_1(\Delta R_{t-1,j}, C_{tj})$.

There are no detailed statistics on costs C_{tj} of development activities in gas fields. The only data of sufficient detail show number of gas development wells in the 1950's and 1960's, by drilling district. These are not wholly indicative of costs; some wells cost much more than others, because of depth and strata conditions, and wells themselves are joint factor inputs both of "capital" and of "knowledge" on surrounding geological conditions. The knowledge input is particularly important since further wells, even for development purposes alone,

contribute to forming new estimates of reserves in surrounding trap of field formations. Thus wells W_{tj} may be a joint input for this and succeeding values of ΔR_{tj}. It might be expected that substituting wells $W_{t-1,j}$ for C_{tj} so that $\Delta R_{tj} = f(\Delta R_{t-1,j}, W_{t-1,j})$ would indicate only imperfectly the important factors in reserve discoveries, at least from the "engineering" point of view.[52]

The demand side of gas markets has been described in a number of different ways. Here, the owners of new reserves are assumed to develop any reserve discovery after bids from various pipeline buyers; the buyers set the terms of the new reserve contract in competition with each other, but they make up the side of the market that sets the terms. One of the terms is purchase price P_{tj} in the field, and P_{tj} depends on the pipelines' own costs of providing transport service from each district. The volume of discoveries is important in setting these costs -- large discoveries provide the opportunity to put in large-scale gathering lines which reduce the costs of transporting an additional Mcf of gas; in simplest terms, the average new contract price in a district depends on reserves ΔR_{tj} discovered there, or $P_{tj} = f(\Delta R_{tj})$. There is another cost

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[52] All series used for fitting functional relationships are described in detail in the Appendix to the article, P.MacAvoy, "The Regulation-Induced Shortage of Natural Gas," Journal of Law and Economics, Vol. XIV, No. 1 (April, 1971).

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determinant of bid prices. The greater the distance the source of reserves is from final home and industrial gas users, the greater the costs to the pipelines and consequently the less the field offer price for these reserves;[53] that is, $P_{tj} = f(\Delta R_{tj}, M_j)$ for mileage M of district j from the point of resale to retail distributors, where increased mileage is expected to lead to reduced bid prices. The important general demand determinant of bid prices is the final consumer, however. In years in which prices of substitutes are rising, and incomes or other determinants of personal consumption are increasing, then the bid prices should be higher. The first indicator of a final consumer demand increase is an increase in the price of substitutes, as shown by the index of all fuel prices fp_t. The price $P_{tj} = f(\Delta R_{tj}, M_j, fp_t)$, where fp_t is the index of fuel prices by consuming region, and the higher this index the higher the expected bid prices of the pipeline buyers of gas.

The "engineering" supply-demand relationships before field price regulation can be characterized as follows, where each variable is in logarithms:

$$\Delta R_{tj} = a_1 + b_1 \Delta R_{t-1,j} + c_1 W_{t-1,j} \qquad (1)$$

$$P_{tj} = a_2 + b_2 \Delta R_{tj} + c_2 M_j + d_2 fp_t . \qquad (2)$$

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[53] A diagrammatic exposition of this argument is provided in P. W. MacAvoy, Price Formation in Natural Gas Fields, op. cit., chapter 3.

The quantity of reserves discovered (1) equals the quantity demanded (2) each year. This is the result of competitive market clearing, by year-to-year changes in the contract prices (reflecting recent pipeline transmission costs and final consumer fuel prices). The markets clear as a result of new reserves ΔR_{tj} being made available, and then by the producers accepting the highest bid prices of pipeline buyers for these new reserves.

The procedure for fitting these equations for the 1955-1960 experience has been to complete a two-stage least squares (2SLS) regression analysis. The data series for these years are used to fit the general log linear form of the first stage equation by least squares as follows:

$$\log(\Delta R_{tj}) = -30.7240 + \underset{(.1050)}{.6547} \log(\Delta R_{t-1,j}) + \underset{(.1479)}{.2694} \log(W_{t-1,j})$$

$$+ \underset{(1.0398)}{.0526} \log(M_j) + \underset{(5.3848)}{6.7685} \log(fp_t); \qquad R^2 = .5193$$

for 66 observations of 11 drilling regions for EMW. Then regression equation values $\Delta\hat{R}_{tj}$ for the given values of the independent variables in each of the 66 observations are used with the actual values of the exogenous variables to fit the demand least squares equation. This second stage least squares equation from the same 66 observations of EMW before regulation is as follows:

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$$\log(P_{tj}) = -.9898 + \underset{(.0160)}{.1307} \log(\Delta\hat{R}_{tj}) - \underset{(.1309)}{.1260} \log(M_j)$$

$$+ \underset{(.6821)}{.8231} \log(fp_t); \qquad R^2 = .5498.$$

A cursory inspection shows that these fitted equations appear to be reasonable economic relations. Reserves increase the most where previous reserves and drilling activity are the greatest, at least in these years and these regions. The second equation indicates that offer prices are higher where the new "packages" of reserves are larger, the distance to final markets is less, and when the fuel price index is higher. All are in accordance with competitive relations between final demand and bid prices in the field.[54] But these are minimum standards of reasonableness. In statistical terms, the log linear form in the first equation "fits" to the extent that the coefficient of past reserves is "statistically significant" and the equation "explains" 52 percent of the variance in discovered reserves.[55] The demand equation cannot be said to have "statistical

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[54] The behavior of prices and reserve volumes in competitive field markets is described in detail in P. MacAvoy, Price Formation in Natural Gas Fields, op. cit., chapters 2-4. That description is in terms of a "reduced form" equation for prices assuming reserve supply to be dependent upon geological conditions in the strictest sense, in the shortest run time horizon. With inelastic supply, the reduced form equation becomes the demand equation given here.

[55] The coefficient b is "statistically significant" when the hypothesis that it has a true value of zero is rejected by $b_i/Sb_i > 2.0$ (where Sb_i is the estimated standard deviation in the distribution of computed b_i). This value of "t" > 2.0 would occur by chance in less than 5 calculations out of 100 when the

significant" coefficients for the independent variables, because of the presence in the equation of a fitted variable $\Delta\hat{R}_{tj}$; but the "quasi-significant" variable $\Delta\hat{R}_{tj}$ and the two other variables together explain 55 percent of the variance in bid prices (with $R^2 = .55$). This is to say that much remains unexplained.

These supply and demand functions may comprise an initial description of "market-clearing" for newly discovered reserves in the later 1950's. If this is the case, how far did actual prices and quantities depart from "clearing" prices and quantities in those years? Actual reserves were almost the same as those amounts that would have made supply equal to demand: the average discovery in the 11 districts over the five years was 403 billion cubic feet, while the range was from less than 10 billion to more than 8,000 billion cubic feet; on average, more than one-half the "market-clearing" estimates of reserves were within 3 billion cubic feet of these actual volumes and more than nine-tenths of the estimates were within 9 billion cubic feet of actual reserves.[56] Actual prices, while averaging 14.7

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[55] cont'd. zero value hypothesis held, so that it is "safe" to reject the hypothesis in favor of the alternative of b_1 significantly greater than zero. The equation "explains" that proportion of the variance in the dependent variable indicated by R^2, defined as the ratio of variance around the regression line to total variance in the dependent variable. The values of R^2 are shown for each equation, and they are .52 and .55 respectively.

[56] The standard error of estimate around the regression equation for reserves had a log value of 1.062, so that -- assuming log normality of the residuals of actual from regressed reserves -- more than 1/2 of the actual values were within 1.062 of the regressed values.

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cents per Mcf, were no more than one cent per Mcf greater or less than "market-clearing" prices in one-half the observations, and no more than three cents in almost all of the observations. The model showed no tendency for systematic departures from actual behavior (except in the South Louisiana district where the model expected less new reserves each year than the 2,000 to 8,000 billion cubic feet discovered). The impression is that markets in the 1950's behaved as though they cleared each year.

The regression equations can be used to simulate "unregulated" sales in gas field markets in the 1960's. If the conditions described by the equations for the 1950's continued through the 1960's, then the supply and demand curves would produce forecast values of reserves and prices ΔR^*_{tj}, P^*_{tj} from introducing actual 1961-1967 values of the "outside variables" $R_{t-1,j}$, $W_{t-1,j}$, M_j, and fp_t into the regressions. The values R^*_{tj} and P^*_{tj} reproduce the 1955-1960 "market-clearing" conditions for given 1961-1967 levels of well drilling, mileage, previous reserves and final consumer demands. In that sense, the simulated R^*_{tj} and P^*_{tj} can be said to describe behavior in the 1960's as if there were no field price regulation.

The "regulated" and "unregulated" prices and quantities are shown in Table 4 for the first seven years of the 1960's.[57]

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[57] 1968 and 1969 are not shown for two reasons. First, data on actual prices and production for the 11 drilling regions have not been made available by the F.P.C. Also, the announced volumes of discovered reserves in year "t" are less in the year or two after discovery than these amounts for year "t" but readjusted five years after discovery, so that there is a decline in discoveries for reporting reserves alone. This condition makes it unlikely that 1968 and 1969 can yet be analyzed.

Table 4

PRICES AND PRODUCTION OF GAS FOR THE EAST COAST AND THE MIDWEST, 1961-1967

Year	Average Price † (¢/Mcf)	Simulated "unregulated" Average Price (¢/Mcf)	Actual New Reserves (billions of cubic feet)	Simulated "unregulated" Reserves (billions of cubic feet)
1961	18.0	17.2	5855	8400
1962	19.1	16.2	5805	5874
1963	16.5	16.4	4946	5369
1964	16.8	15.2	5558	3869
1965	17.5	15.9	6115	4830
1966	17.3	16.7	4213	5969
1967	17.5	16.7	3682	5077

† The weighted average price $\Sigma P_{tj}\Delta R_{tj}/\Sigma\Delta R_{tj}$, where ΔR_{tj} is new reserves in drilling region j in year t.

The two price series are not the same: "unregulated" prices seem somewhat lower than the average of the area rates each year, more than two cents lower in 1962 and 1.5 cents lower in 1965. There would seem to have been no detectable price-reducing effect from area rate regulation -- rather, area rates seem

excessively high. In contrast, actual reserves were much less than reserves simulated for "markets without regulation." The actual levels of reserves averaged 8 percent less than the simulated levels over the seven-year period.[58] This greater volume of discoveries at lower prices without regulation would seem to be a mistake of the model -- regulation keeps prices at higher levels. These are results induced by the particular supply conditions in the first regression equation. The reserve equation each year forecasts more new discoveries than actually take place, which are than "cleared" by reduced prices in the demand equation. The reserve equation forecasts are "too large" probably because regulatory conditions in the 1960's changed the structural relation between past and present discoveries. In recent years, less was being found on succeeding rounds of reserve accumulation than was the case in the absence of regulation of prices in the 1950's. In this sense, the "engineering" model is not descriptive.

The EMW model results can be compared with results from an analysis of production of gas under new contracts for delivery to pipelines to the West Coast. The new contract transactions in the 1955-1960 period in W were used to fit the supply and demand equations as follows:

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[58] Both levels are based on the actual additions to reserves the previous year $\Delta R_{t-1,j}$.

$$\log(\Delta R_{tj}) = 108.9634 + \underset{(.2466)}{.3068} \log(\Delta R_{t-1,j}) - \underset{(.3367)}{.7083} \log(W_{t-1,j})$$

$$- \underset{(11.5421)}{19.0920} \log(M_j) + \underset{(7.2320)}{6.1314} \log(fp_t); \qquad R^2 = .7063$$

$$\log(P_{tj}) = -19.0884 + \underset{(.0369)}{.0282} \log(\Delta \hat{R}_{tj}) + \underset{(1.2674)}{1.6094} \log(M_j)$$

$$+ \underset{(1.3648)}{2.2729} \log(fp_t); \qquad R^2 = .2501.$$

These equations fit the data poorly -- if anything, worse than those given above for EMW buyers. The reserve equation explains 70 percent of the variance in the dependent variable, but the independent variables all have statistically insignificant coefficients.[59] The second equation cannot be said to have "significant" coefficients because of the previous fitting of the variable ΔR_{tj}; but the sign of mileage is perverse and the values of the other coefficients do not resemble those in EMW. There are special reasons for this behavior in West Texas and New Mexico. There are only three districts there, and drilling has been following quite different patterns in one as compared to the other two districts; the annual averages of the two patterns,

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[59] On the usual tests for the ratio of the computed coefficient to the computed standard error of the coefficient (shown below each coefficient in parenthesis). The ratios do not exceed the value of 2.0 necessary to reject the hypothesis that the coefficient value is zero.

with only 18 observations over six years, have had erratic effects on overall new reserves throughout the W area. Buying has been dominated by a single pipeline that established a policy in the early 1950's of paying higher (discriminatory) prices in the farther West Texas region.[60] The highly uncertain supply behavior in the first equation, coupled with non-competitive bid pricing in the second equation, makes this model a poor forecast vehicle.

The models of "unregulated" discoveries in the EMW and the W regions in the 1950's show the great imprecision in using simple "engineering" equations for assessing the effects of field price regulation. The regulated prices were similar to, if somewhat higher than, the regression-derived "unregulated" prices where a comparison was attempted. The regulated discoveries, however, seem to have been less than expected from markets without regulation. Both follow from the fitted inelastic supply function being an inadequate description of the actual supply function. Any final assessment of the effects of regulation requires a more detailed analysis of field market supply.

An economic model of supply should take account of price incentives for exploratory drilling; at the least, the changes

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[60] Cf. P. MacAvoy, Price Formation in Natural Gas Fields, op. cit., at chapter 5; this pattern of buyer's discrimination is explainable by entry of competing buyers only at the farther location.

in supply conditions after regulation shown in the "engineering" model should be revealed directly as disincentives from controls on prices. The demand equation should take more account of changes in final markets for gas, and there should be a direct relation established between discoveries and actual production of new reserves under new contracts, in order to assess the security of reserve "backing."

The determinants of the supply of newly discovered reserves should include the (expected) price for production of these reserves. The "economic", as opposed to the "inelastic supply", view is that higher prices on new contracts bring forth more gas well capacity and the additional capacity, by drilling out more of the regions likely to contain gas, increases the amount of new reserves that are discovered. If actual new contract prices are good surrogates for the prices forecast by the drilling companies before development begins, then the amount of drilling of wells $W_{tj} = f(P_{tj})$. Also, more gas drilling takes place where there are prospects of more profitable oil finds. This may be indicated by increased drilling when there is an increase in the all-fuels price index (fp_t). Last of all, the analysis of drilling should recognize that larger amounts of information gathered in the previous year increase the drilling for new reserves in any region. This information is increased by adding to the amount of drilling in that district in the

previous year, $W_{t-1,j}$. The supply function for reserves thus can be taken to be:

$$\Delta R_{tj} = f(\Delta R_{t-1,j}, W_{tj})$$

$$W_{tj} = f(P_{tj}, fp_t, W_{t-1,j})$$

for each drilling region in the EMW and W markets in the 1955-1960 period.

Additional production each year depends upon the amount of newly discovered reserves ΔR_{tj} and on the costs of holding these reserves. Also, it should depend on characteristics of short term demands in final consumer markets -- if, for example, prices of alternative fuels were rising while production from these alternative sources was not, then demand for gas in the short term should increase and these demands should be met by more production out of new reserves. For another example, new gas service introduced into a final consuming region may result in gas production increases and price decreases for alternative fuels.

Although the causal relations cannot be established and measured very exactly, a first indication might be $nQ_{tj} = f(\Delta R_{tj}, i_t, fp_t)$ for nQ production from new contracts signed in year t in district j, new reserve discoveries ΔR_{tj}, the current rate of interest i[61], and the fuel price index fp_t. The statistics

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[61] The rate of interest i is a measure of the costs of holding reserves. As these costs increase, the holding period for reserves should decline -- in other words, the production rate out of new reserves should increase.

for fitting this equation are for each drilling region in the same markets and time periods as for the supply equation of newly discovered reserves.

The demands for new reserves are assumed to conform to the market conditions posited in the "engineering" model. New contract prices P_{tj} bid by pipeline buyers depend on the volume of newly discovered reserves ΔR_{tj} in that drilling region; and, as an additional factor, the average level of bid prices in any year depends on the sum total of all new reserves found that year (with more reserves $\Sigma\Delta R_{tj}$ reducing the level). New prices are also likely to be affected by the distance M_j from the point of production to final markets and by conditions of final consumers' demand for gas and other sources of energy. There are likely to be two important consumers' demand conditions. First, the prices of substitute fuels should have a direct effect, so that higher fuel prices signal increased demands for energy which increase bid prices for new gas contracts. As a result, we should observe in $P_{tj} = f(\Delta R_{tj}, \Sigma\Delta R_{tj}, M_j, fp_t)$ that a change in bid prices is in the same direction as the change in the fuel price index fp_t. Second, new contract prices for gas should be affected by the size of the final markets measured in terms of population and income. Additions to the size of final markets and to purchasing power can be termed $\Delta N\Delta Y$, for population increase ΔN and per capita income increase ΔY, and the greater

the value of $\Delta N\Delta Y$, the greater the new gas reserves price. The demand relation is presumed to be:

$$P_{tj} = f(\Delta R_{tj}, \sum_j \Delta R_{tj}, M_j, fp_t, \Delta N\Delta Y)$$

for the same regions and time periods as for the three supply functions.

Competitive markets that clear gas reserves ΔR_{tj}, gas production ΔQ_{tj}, the number of development wells W_{tj}, and initial contract prices P_{tj}, are thus assumed to depend on the "outside" or exogenous variables $\Delta R_{t-1,j}$, fp_t, $W_{t-1,j}$, $\Delta N\Delta Y$, M_j and i_t. Data series for each of these variables have been constructed for the pre-regulatory period 1955-1960 in eleven drilling regions in EMW and four drilling regions serving the W final demand territories (see footnote 52 on page 131). These data are used to fit the supply and demand relations by two stage least squares, with the four endogenous variables, ΔR_{tj}, ΔQ_{tj}, W_{tj}, P_{tj}, simultaneously determined. The procedure is to find "reduced form" least squares equations for each of ΔR_{tj}, ΔQ_{tj}, W_{tj} and P_{tj} separately, given the exogenous variables, and then use the fitted values $\Delta\hat{R}_{tj}$, $\Delta\hat{Q}_{tj}$, $\hat{W}_{tj}$, and $\hat{P}_{tj}$ to find the least squares supply and demand equations. The reduced form regressions for EMW are as follows:

$$\log(\Delta R_{tj}) = -109.7031 + \underset{(.1045)}{.6439} \log(\Delta R_{t-1,j}) + \underset{(7.9224)}{17.1926} \log(fp_t)$$

$$+ \underset{(.1573)}{.3677} \log(W_{t-1,j}) + \underset{(3.6100)}{6.7137} \log(\Delta N \Delta Y) - \underset{(2.3084)}{4.8325} \log(i_t)$$

$$SER = 1.0396 \qquad R^2 = .5550$$

$$\log(\Delta Q_{tj}) = -101.5247 + \underset{(.0915)}{.5821} \log(\Delta R_{t-1,j}) + \underset{(6.9359)}{12.6642} \log(fp_t)$$

$$+ \underset{(.1377)}{.6927} \log(W_{t-1,j}) + \underset{(3.1605)}{9.3609} \log(\Delta N \Delta Y) - \underset{(2.0209)}{6.0958} \log(i_t)$$

$$SER = 0.9101 \qquad R^2 = .6746$$

$$\log(W_{tj}) = -54.4059 + \underset{(.0337)}{.1106} \log(\Delta R_{t-1,j}) + \underset{(2.5521)}{10.1146} \log(fp_t)$$

$$+ \underset{(.0507)}{.7496} \log(W_{t-1,j}) + \underset{(1.1629)}{1.6503} \log(\Delta N \Delta Y) - \underset{(.7436)}{.9211} \log(i_t)$$

$$SER = .3349 \qquad R^2 = .8744$$

$$\log(P_{tj}) = 3.0950 + \underset{(.0116)}{.0800} \log(\Delta R_{t-1,j}) - \underset{(.8806)}{.5851} \log(fp_t)$$

$$+ \underset{(.0175)}{.0425} \log(W_{t-1,j}) - \underset{(.4013)}{.3035} \log(\Delta N \Delta Y) + \underset{(.2566)}{.5151} \log(i_t)$$

$$SER = .1156 \qquad R^2 = .6803$$

for 66 observations in 11 drilling regions over the six year pre-regulation period ending in 1960. Little can be said of these equations since they are not direct tests of economic relations; however, they fit well in the usual statistical sense, given that many coefficients are statistically significant and the percent of variation in each endogenous variable explained

by the equation is more than 55 percent.[62] The instrument values $\Delta\hat{R}_{tj}$, $\Delta\hat{Q}_{tj}$, $\hat{W}_{tj}$, and $\hat{P}_{tj}$ vary from the observed values by negligible amounts, given that the standard error of residuals in each regression was small (as shown by the listed values of SER).

The values of $\Delta\hat{R}_{tj}$, $\Delta\hat{Q}_{tj}$, $\hat{W}_{tj}$, and $\hat{P}_{tj}$ have been used to find four regressions, one for the supply of new reserves, the second for the supply of wells, the third for new production, the last for the demand for new reserves. The supply of new reserves and the number of wells equations for the 1955-1960 period are as follows:

$$\log(\Delta\hat{R}_{tj}) = 0.2765 + \underset{(.0292)}{.5894}\log(\Delta R_{t-1,j}) + \underset{(.0489)}{.4364}\log(\hat{W}_{tj});\ R^2 = .9400$$

$$\log(W_{tj}) = -35.0582 + \underset{(0.1206)}{1.0296}\log(\hat{P}_{tj}) + \underset{(0.5656)}{6.7314}\log(fp_t)$$

$$+ \underset{(0.6188)}{0.6872}\log(W_{t-1,j});\quad R^2 = .9848$$

which show positive cumulative effects from previous reserve findings and wells, and the positive effects from both new gas

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[62] The tests for significant coefficients indicate differences from zero for three or four coefficients in each equation. The values for R^2 -- indicating the percent of dependent variable variance explained by the regression equation -- are from .55 for new reserves to .87 for wells drilled.

contract prices and the all-fuels price index. The elasticity of reserve supply with respect to new contract gas price is estimated to be (.4364)(1.0296) = .45, so that a 10 percent price increase should have led to a general 4.5 percent increase in discovery of new reserves.

The production equation is as follows:

$$\log(\Delta\hat{Q}_{tj}) = 44.7285 + \underset{(0.0322)}{1.1091} \log(\Delta\hat{R}_{tj}) + \underset{(0.3514)}{1.1567} \log(i_t)$$

$$- \underset{(1.9389)}{10.9032} \log(fp_t); \qquad R^2 = .9528$$

which shows a positive production-reserve relation, and a positive production-interest rate relation, but a negative production-fuel price relation. The elasticities of production with respect to reserves and interest seem to have been approximately one, and were "quasi-statistically significant."[63] The elasticity with respect to the fuels price index was negative and larger; that is, declines in the fuels price index in the late 1950's were accompanied by more than proportionate gas production increases. This would seem to have been a result of movements in this period towards an equilibrium share for natural gas of the total energy market in regions receiving gas for the first time.

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[63] At the second stage of 2SLS, it is not possible to test for statistical significance; we use the terms and show the standard errors only to record the computed results as completely as in ordinary least squares (OLS).

The demand equation has also been estimated in the second stage of two stage least squares as follows:

$$\log(\hat{P}_{tj}) = -28.8494 + \underset{(0.0055)}{0.1210} \log(\Delta\hat{R}_{tj}) - \underset{(0.0879)}{0.7138} \log(\sum_j \Delta\hat{R}_{tj})$$

$$- \underset{(0.0461)}{0.1232} \log(M_j) + \underset{(0.8726)}{6.6067} \log(fp_t) + \underset{(0.1131)}{1.3798} \log(\Delta N \Delta Y)$$

$$R^2 = .9205$$

with positive elasticities for four variables and negative elasticities for two variables. The elasticity of bid prices with respect to total reserves (the reciprocal of the usual elasticity of demand) is -.72, while the elasticity with respect to the all-fuels index is +6.6 and with respect to income is +1.38. The other coefficients -- for variables differentiating the drilling regions -- are as expected from the economics of pipeline costs and demand.

This four-equation analysis shows that the supply of newly discovered reserves and of new production depends upon new contract bid prices, and these bid prices depend on the size of total discoveries, on pipeline costs, and on conditions of demand in final gas resale markets.[64]

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[64] The four equations together make up an equilibrium system that "describes" well the actual prices and discoveries in the late 1960's. An indication of the closeness of description is the standard error of the regression of price, equal in log terms to .069, while average price in log terms was 2.6801; approximately 1/2 of average prices were within ±.069 of the log value of 2.6801 (given average values of the independent variables) and 90% of prices were within ±.198 of the log value under these conditions. Similarly, 1/2 of the actual volumes of discovered reserves were within 0.2796 of those expected in the regression equation equilibrium system; for example, at the mean regression value of 5.9981, 1/2 the values were equal to this amount, plus or minus .279

These conditions make it likely that regulation, with ceilings on prices, has had a substantial effect on gas reserve discovery and disposition. In order to assess the possibility, the "second stage" regression equations have been used, along with 1961-1967 values of the independent variables, to find the values ΔR^*_{tj}, ΔQ^*_{tj}, W^*_{tj}, and P^*_{tj} which solve these four equations simultaneously (in other words, "clear" the gas market as if there were no price ceilings). The simulated or "unregulated" values for EMW are compared with actual values in Table 5.

Table 5

PRICES AND PRODUCTION OF GAS FOR THE EAST COAST AND THE MIDWEST, 1961-1967

	Average Price	Simulated or "unregulated" Price	Production (billions cu.ft.)		Reserves (billions cu.ft.)	
Year	(¢/Mcf)	(¢/Mcf)	actual	simulated "unregulated"	actual	simulated "unregulat
1961	18.0	19.2	314	400	5855	8189
1962	19.1	25.3	160	345	5805	7031
1963	16.5	26.4	461	333	4946	6582
1964	16.8	30.8	206	390	5558	5685
1965	17.5	36.8	374	418	6115	7134
1966	17.3	43.2	335	473	4213	8547
1967	17.5	42.1	582	345	3682	7369

The simulated reserves show strong incentives from higher prices when markets are allowed to clear. Simulated reserves and prices in this table are generally much greater than actual reserves and prices. The simulated volumes of market-clearing reserves were 140 percent of the actual new reserves over this period. The expected prices were 14.4 cents per Mcf greater than actual prices over this period, and the difference was increasing over time from less than 10 cents up to 1963 to more than 20 cents in the last two years. The market-clearing process would have bid prices up greatly over the period, increasing newly discovered reserves so as to fill part of the existing supply-demand gap.

Actual production was greater than simulated production, given the amount of simulated newly discovered reserves. Simulated production from new reserves over the seven-year period averaged 386 billion cubic feet from new contracts each year, while actual production averaged 347 billion cubic feet. Even though simulated production was greater than actual production, while simulated reserves were greater than actual reserves, the hypothesized "unregulated" rate of utilization of new reserves would have been much less than the actual or "regulated" rate of utilization.[65]

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[65] This can be seen by comparing the rates of utilization. Simulated production out of simulated reserves was 5.3% on average, while actual production out of actual reserves was 6.7% on average.

One reason for the difference in rates of production may have been the differences between market-clearing and regulated prices. The higher prices in the market-clearing model were compatible with slower rates of production -- slower because final buyers would not have demanded as much gas when higher field prices were passed through to them.

Some of the same conditions have been evident in the West Coast market. The reduced form equations for this market contain some variables with statistically significant coefficients; in particular, the wells variable lagged one period was statistically significant in the ΔR_{tj}, the ΔQ_{tj} and the W_{tj} equations, and the distance variable was statistically significant in the ΔQ_{tj} equation. The R^2 values ranged from .65 (for the P_{tj} equation) to .91 (for the W_{tj} equation). But the second stage regressions, with first stage values of $\Delta \hat{R}_{tj}$, $\Delta \hat{Q}_{tj}$, $\hat{W}_{tj}$ and $\hat{P}_{tj}$ inserted where appropriate, were economically reasonable only in part. The supply of reserves was directly related to previous year's reserves but inversely related to the number of exploratory wells. The number of wells was in turn inversely related to price $\hat{P}_{tj}$, so that there was a direct but small price elasticity of supply equal to the product of these two negative coefficients, or (-.2283)(-.9149) = .2088. Production in new contracts was dominated by reserve discoveries, with an elasticity of +.9357; but the elasticity

with respect to interest was negative and with respect to fuel prices was positive -- the opposite of those shown in EMW. The demand price for new production was related positively to reserves $\Delta\hat{R}_{tj}$, distance M_j, income $\Delta N\Delta Y$, and fuel prices fp_t, and negatively to $\sum_j \Delta\hat{R}_{tj}$. Here the ΔP_{tj} elasticity with respect to total reserves was -.2322 (so that the reciprocal -- the elasticity of demand -- was very large).

Forecasts from this equation system are not satisfactory for a number of reasons. There are conceptual problems with the fitted equations. The model contains unlikely relations, particularly the inverse relation between new reserve discoveries and the number of wells drilled; it is not likely that accurate forecasts of the 1960's would follow from replicating the pattern and thus showing increased discoveries from decreased drilling. The model also suggests that significant increases in final demands in California and other western states have a very small effect on the bid prices of gas in West Texas (the elasticity was only 0.0704). This did occur as a result of monopsony pipeline control of prices in the 1950's, but it could not be expected to continue throughout the 1960's, given that there has been substantial additional entry of pipelines on the demand side of markets there. As a result, the model based on monopsony demand should not simulate the 1960's well.

The model does not simulate well. Reserves and prices in two of the three districts in the western area are lower than

simulated reserves and prices. But in the third region, more than 1300 billion cubic feet of new reserves were discovered in each of five years, where the 1955-1960 average was half this amount and the 1961-1967 simulated reserves are also half this amount. There were special supply and demand reasons for the results. On the supply side, all of these additional amounts were dedicated to intrastate buyers at unregulated prices from 2 cents to 6 cents per Mcf above the ceiling area rates, so that price incentives not shown by the controlled interstate prices were available -- and these intrastate prices did affect supply. On the demand side, substantial additional intrastate demands were created by the too-low ceiling prices, and these were centered on projects for new Texas-only pipelines when it was apparent that the volumes of reserves were sufficient for large scale systems. Supply and demand were both greater than expected with the historical regression model, and prices cleared the intrastate portion of this market at higher levels than 1961-1967 interstate ceiling prices.[66] Thus the reasons for these special results are regulatory.

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[66] This disequilibrium with two prices can occur only when all substantial sales are made intrastate, and there is still an intrastate premium. The interstate prices are thus nominal, for negligible sales. This seems to have occurred only in the Permian Basin in W, and thus makes the comparison of interstate-intrastate equilibrium and interstate rate ceiling disequilibrium (assuming intrastate equilibrium) impossible.

The overall impression from EMW and W together is that new reserve findings would have been more than 40 percent greater if there had been no field price regulation. The effects of "clearing prices" on both supply and demand would have been apparent. The higher market-clearing prices in the EMW buying area would have brought forth additional discovered reserves equal to roughly four-fifths of the supply-demand gap in the inventory shortage if 14.5 years of reserve backing are needed, or one-third of the gap if 20 years of reserve backing are needed. Higher prices also should have led to some reductions in the quantities demanded of newly discovered reserves. This last is not observable, since the comparison here is between supply of discovered reserves at the price ceilings and supply-demand equilibrium without price ceilings; but it is possible that such price increases would have eliminated the other one-fifth to two-thirds of the supply-demand gas, in the same way that price changes cleared markets in the 1950's.

The impact of the gas shortage on final consumers. The "shortage of natural gas" has been attributed to F.P.C. field price regulation, in the sense that the continuation of 1955-1960 market processes rather than regulatory ceiling prices would not have resulted in the realized excess demands for reserves. Given these results, the question now is who has a

grievance with the Commission: who experienced the shortage, and what were his economic losses as a consequence?

The gains and losses for final consumers, under conditions of reduced reserves and increased production, are diverse and obscure, and evidence is mostly replaced with speculation. One view is that the shortage benefits everyone -- that the *increased rate* of gas production at the present time, even from restricted reserves, is an improvement over the *restricted rate* of production that would have occurred without regulation. The reason given is that more gas is delivered to those *favored by regulation*, merely causing the reserve backing for delivery to others to be depleted earlier. All of the additional new gas production occurring at present under regulation might go to home consumers, for whom pipeline and retail gas rates are controlled by both national and state regulation. The remaining commercial and industrial consumers without the "usual" reserve backing might go to "close" substitutes at a somewhat earlier time than otherwise. There is an alternative view, that increased production now has the effect of depleting the reserve stock not only of new home consumers, but of those long established home consumers that had been offered "twenty-year backing" at the time field price regulation began. If this is the case, then those with the grievance are those that should have been protected by regulation.

The indications of patterns of distribution support the latter speculation. The information is based on dividing the history of gas sales into three periods. The first two have been described by Balestra[67] as: (1) an "innovating" period, 1950 to 1957, for natural gas pipeline construction and initiation of service to industrial and home consumer classes, and (2) a "maturing" period, 1957 to 1962, of extension of more service to established customers. The third phase, 1962 to 1968, is characterized here as a "reallocation" period, with shifts of service from one of the classes to the other. The allocation of quantities to each customer class can be described for each of these sub-periods; reallocation takes place when sales to one group are decreased and prices are increased, while the other group experiences sales increases and price decreases.[68]

The relative consumption levels, sales revenues, and prices for residential and industrial gas customers are shown in Table 6.[69] There is little variation in proportions of total consumption of the two classes between the first two periods. The fraction of gas consumed in residential use increased, and

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[67] Pietro Balestra, The Demand for Natural Gas in the United States, A Dynamic Approach for the Residential and Commercial Market, 86-89 (46 Contributions to Economic Analysis, 1967).

[68] This description is based on W.P. Schlarb, An Estimation of Supply Allocation Among User Classes of Natural Gas Utilities (unpublished M.S. dissertation, Massachusetts Institute of Technology, June, 1970). The author's assistance here is lavishly acknowledged.

[69] Here "price" is average revenue per unit of sale.

Table 6

PERCENTAGE OF NATURAL GAS SALES AND TOTAL REVENUE AND AVERAGE REVENUE BY CUSTOMER CLASS IN THE UNITED STATES

	Year			
	1950	1957	1962	1968
Percentage of Sales				
Residential	39.1	41.3	44.5	43.0
Industrial	60.9	58.7	55.5	57.0
TOTALS	100.0	100.0	100.0	100.0
Percentage of Revenue				
Residential	67.6	67.9	68.7	66.8
Industrial	32.4	32.1	31.3	33.2
TOTALS	100.0	100.0	100.0	100.0
Average Revenue (cents/therm)				
Residential	6.11	8.33	9.50	9.39
Industrial	1.88	2.77	3.47	3.51

Source: Percentages and average revenues have been calculated from data in various issues of Amer. Gas Assoc., Gas Facts, as in W.P. Schlarb, *op. cit.* Residential use includes commercial; industrial use includes other.

price increased greatly in both classes, so that it would appear that increasing demands in both classes were met by increased production, but a larger proportion went into residential sales. In the third period, the trends were reversed and the percentage of use by residential customers declined while the industrial percentage increased. There was a slight (insignificant) decline in residential average price and a very slight rise in industrial average price.

Differences in the growth patterns of the two classes are shown in Table 7. The growth rates were much the same in the "innovating" period, with increased revenues keeping pace with increased consumption in the two classes. In the "maturing" period, revenues on industrial consumption increased faster than on home consumption because industrial prices went up faster. In the last or "reallocation" period, industrial consumption and prices both increased at a faster rate than in the home sector, resulting in an annual increase in revenues on industrial consumption 1.5 percentage points greater than on home consumption.

Table 7

ANNUAL COMPOUND RATE OF INCREASE OF NATURAL GAS CONSUMPTION, REVENUE AND AVERAGE REVENUE, BY CUSTOMER CLASS IN THE U.S. (Percent)

	Period		
	1950-1957	1957-1962	1962-1968
Growth of Consumption			
Residential	10.9	7.5	5.5
Industrial	9.4	4.8	6.6
Growth of Revenue			
Residential	15.9	9.7	5.3
Industrial	15.6	10.4	6.8
Change of Average Revenue			
Residential	4.5	2.7	(0.2)[a]
Industrial	5.7	4.6	0.2

Source: Compound annual growth rate of consumption, revenue and the average revenue have been calculated from series in the Amer. Gas Assoc., Gas Facts, as in W.P. Schlarb, op. cit. Residential use includes commercial; industrial use includes other.

( )[a] indicates decrease.

Those differences had important effects on prices and profits for the pipelines by classes of customer. In 1950, the average revenue from industrial sales was relatively very low, less than one-third that of residential use. However, during the two periods 1950-1957 and 1957-1962, industrial gas prices increased at a rate almost 25 percent greater than that in the residential sector (with consequent large increases in marginal revenues from industrial sales -- see Table 8). This could be attributed to generally slow response to increased demands in this class. Those "direct sales" of pipelines to industrial consumers were not regulated by the Federal Power Commission but only by State Commissions with varying standards and effectiveness in enforcing their standards. But it was clear that those customers under regulation -- the residential and commercial customers -- were to be given precedence in growth. Relatively greater demand growth, and relatively less supply growth, led to sharply rising returns at the margin on industrial sales.

Table 8

PIPELINE REVENUES IN THE UNITED STATES MARKET

	Period		
	1950-1957	1957-1962	1962-1968
Marginal Revenues (cents/therm)			
Residential	9.18	11.76	9.13
Industrial	3.21	5.73	3.59

Source: from W.P. Schlarb, op. cit. The calculations are changes in revenues divided by changes in sales.

By the middle of the second period, demand growth had slowed down. Balestra, writing of this period, concludes that "in what may be termed the mature state ... the gas industry is facing an increasingly competitive situation."[70] Incremental demand had become a matter of "normal growth of population, household formation and the like."[71] His econometric analysis showed "an upward trend in price elasticity"[72] in this period for new residential demand. Even so, relatively more gas was distributed to household users. This is shown by price increases at a more rapid rate, and consumption increases at a less rapid rate, in the industrial consumption class in this period.

The third period, from 1962 to 1968, showed the effects of stabilized prices. Average revenues did not change appreciably, and were roughly the same as marginal revenues, from new sales. The stabilization of prices during this period must have come about as the result of: (1) F.P.C. control of wellhead prices, (2) inter-fuel competition especially in industrial use (as shown by Edmund Kitch)[73]. The ceiling field prices were

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[70] Pietro Balestra, op. cit., at 88.

[71] Idem.

[72] Ibid., at 97, 95-99.

[73] E. W. Kitch, op. cit, [see note 10, p. 79], pp. 265-69.

passed along to residential users in near-stabilized average prices, as a matter of F.P.C. regulation of pipeline rates. The industrial price stabilization is another matter, since there were no regulatory requirements to "pass through" area rates. It is more likely that the pipelines allocated the scarce additional gas to industrial users as long as the unregulated profit margin exceeded the regulated, and at the margin encountered more inter-fuel competition. A marked change in market growth patterns is evident in this period compared to the earlier periods, for both customer formation rate (not shown) and consumption growth (shown in Table 7) in industrial use exceed those in residential use. Marginal revenue on industrial sales declined by more than 40 percent -- without gas price controls. Prices of industrial sales had "caught up" to new demands, and these new demands were continuing to be filled at a faster rate than new home consumption demands. This can be described as "reallocation" from home to industrial users.

Nation-wide changes in the "reallocation" period indicate only very roughly the important changes in regional gas markets. The California market shows the period's behavior clearly, since both industrial and home demands were growing rapidly. From the early 1950's, the California market had accounted for 10 percent or more of the total U.S. natural gas utilities' consumption and the percentage had been growing rapidly. Not only have home

demands increased, as a result of the extremely rapid California population increase, but industrial demands have as well. Thermal-electric power generation companies have been a major source of industrial demand in this market. In 1968, for instance, of the total industrial gas use in the U.S., about 31 percent was consumed in electric power generation, and nearly one-third of this was consumed in the Pacific region (principally in California).[74] The distinctive feature has been the lack of any shortage -- the western pipelines have met demands.

The relative distributions of consumption, revenues, and prices for residential and industrial use in California are shown in Table 9. The proportion of gas consumption and revenues by class of customer has changed very significantly from 1950 to 1968.

From the early 1930's to the late 1940's the California gas utilities, either by formal regulatory controls at the state level or voluntarily, had maintained much lower prices per therm for residential use of gas than did other sources of energy. However, as is evident in Table 9, average revenues increased in both classes from 1950 to 1962. This came about as more demand was filled by out-of-state gas supply, and higher purchase costs

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[74] 1969 American Gas Association, Gas Facts; A Statistical Record of the Gas Utility Industry in the United States, 132, Table 124.

Table 9

PERCENTAGE OF NATURAL GAS SALES AND TOTAL REVENUE AND AVERAGE REVENUE BY CUSTOMER CLASS, THE CALIFORNIA MARKET

	Year			
	1950	1957	1962	1968
Percentage of Sales				
Residential	52.0	47.3	44.0	37.3
Industrial	48.0	52.7	56.0	62.7
Totals	100.0	100.0	100.0	100.0
Percentage of Revenue				
Residential	73.1	66.9	63.5	58.8
Industrial	26.9	33.1	36.5	41.2
Totals	100.0	100.0	100.0	100.0
Average Revenue				
Residential	5.55	7.08	8.67	8.15
Industrial	2.21	3.15	3.92	3.40
(cents/therm)				

Source: Percentages and average revenues have been calculated from data in various issues of Amer. Gas Assoc., Gas Facts, as in W. P. Schlarb, op. cit. Residential use includes commercial; industrial use includes other.

were incurred in the Permian and San Juan Basin areas along with higher transport costs to move the gas 1,200 miles from these sources to the California market. After 1962, the pattern of rising prices changed abruptly for both classes of use. This change was coincident with the "market maturity" described earlier in the analysis of United States sales.

Growth rates of consumption and revenue were relatively unchanged from 1950 to 1962, as is shown in Table 10. In the period 1950 to 1957, prices or average revenues for industrial use increased at a rate appreciably greater than those for residential use. In the period 1957 to 1962, prices increased at approximately the same rate in both classes. In the final period, 1962 to 1968, *prices* for industrial use *declined* at more than twice the rate of those for residential use. In this last period, with the price decline, there were significant relative *consumption increases* for industrial use. The pipelines preferred to provide more gas -- at twice the rate of annual increase in residential consumption -- to industrial users, even though industrial prices were declining.

Table 10

ANNUAL COMPOUND RATE OF INCREASE OF NATURAL GAS CONSUMPTION REVENUE AND AVERAGE REVENUE, BY CUSTOMER CLASS, CALIFORNIA MARKET
(percent)

	Period		
	1950-1957	1957-1962	1962-1968
Growth of Consumption			
Residential	6.9	6.2	4.0
Industrial	9.8	9.2	8.9
Growth of Revenue			
Residential	10.6	10.8	2.9
Industrial	15.4	14.1	6.4
Change of Average Revenue			
Residential	3.5	4.1	(1.1)[a]
Industrial	5.2	4.5	(2.4)[a]

Source: Compound annual growth rate of consumption, revenue, and average revenue have been calculated from data in Amer. Gas Assoc. *Gas Facts*, as in W. P. Schlarb, *op. cit.* Residential use includes commercial; industrial use includes other. ( )[a] indicates *decreas*

A practical explanation for this pattern was the strikingly different industrial demand in this last period. In 1960, the F.P.C. authorized Pacific Gas Transmission to construct a transmission system to take gas from the province of Alberta in Canada to California.[75] Pacific Gas and Electric controlled 50.5 percent of the Pacific Gas Transmission system, and dictated the transmission company policy, so that sales were allocated "to the industrial sector" as boiler fuel for Pacific Gas and Electric plants. Demands were changed further when in January, 1964 the Board of Supervisors of Los Angeles County enacted Rule 62.1 which extended the existing Rule 62 ban on the burning of high sulfur fuels to a year-round basis.[76] This meant that virtually all demands for industrial energy in the Los Angeles basin had to be realized as demands for natural gas. These two actions greatly increased demands, but the allocations for these purposes exceeded the usual response by taking new sales in this class to the point of initiating price reductions.

This is classic "reallocation," because it required movement down the demand schedule of the industrial class while maintaining the earlier "quantity" location on the demand schedule

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[75] Pacific Gas Transmission Company, 24 F.P.C. 134 (1960).

[76] Colorado Interstate Gas Company, 31 F.P.C. 434 (1964).

of the residential class.[77] The industrial user received proportionately a far greater value of all new reserves.

The conclusion is that the pipelines in a period of short supply seem to have been allocating relatively more new gas to industrial users, probably as a result of lack of regulation of industrial resales while there was strong regulation on home resales. The regulated rates for deliveries to retail public utility companies increased only when field gas prices or delivery costs changed, and ceiling prices in the field greatly limited these increases. Price could not "ration" new home users. In contrast, prices to industrial consumers depended only on conditions in markets for energy for boiler fuel for industrial use -- conditions that continued to favor natural gas, particularly when new requirements for pollution-free sources of energy were made by local governments. Prices here could "ration" use, and pipelines added to these sales to the point where marginal revenues were close to those on regulated residential resale. This pattern of partial regulation induced priority sales to industrial users.

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[77] The price reduction for home users might suggest a movement down that schedule as well. This reduction, as required by regulation, probably had no such effect since new supplies were allocated at less than the growth rate of households. The most likely occurrence was that of marginal rationing to households.

Regulation in natural gas fields has produced a more rapid rate of production from new reserves, in order to increase the rate of sales to industrial users at unregulated prices. The inventory analysis showed that new demands for reserves by both sectors together exceeded new supplies by more than 50 percent and perhaps as much as 120 percent. There was some indication that the excess demand could have been cleared by price increases inducing 40 percent more supply and inducing a 10 percent reduction in demands. In the absence of market clearing, regulation has had the effect of taking the short supplies and reallocating them from home consumers under the aegis of the Federal Power Commission to the industrial users buying in unregulated energy markets.

The Cost of Regulation

This very complex process of reducing prices for some consumers while creating shortages for others has multiple effects, some of which are now beginning to make themselves known while others will appear in the next ten years. It is still possible, however, to generalize about these effects. There is no conceivable set of results which can make gas consumers as a whole better off than they would be without ceiling price regulation of the 1960's, given the massive scale of the regulation-induced shortage of new reserves. Surely those consumers

who get their established volumes of gas production at 10 to 20 cents less than market clearing prices have been made "better off" by regulation. But their gains cannot be greater than the losses of those who have done without. The losses, as indicated by "willingness to pay", incurred on excess demands from 50 percent to as much as 120 percent of new reserves have been from 20 cents to 50 cents per Mcf. A 10 to 20 cent "betterment" on actual additions to reserves cannot possibly be balanced against a 20 to 50 cent per Mcf "loss" on a similar volume of reserves in excess demand.[78] As a consequence, there is no net consumers' gain to be put against producers' losses -- the producers' losses of millions of dollars per annum in litigation charges, and in the costs of delay, incurred in the certificate and rate proceedings.[79]

Two further extensive regulatory costs are very likely to appear in the 1970's and 1980's. First, industrial firms with expansive demands for energy have likely moved to producing states solely to obtain natural gas not available on the interstate market due to the interstate price ceiling. The extra costs that result from such a move are appropriately part of the cost of regulation. There are no statistical estimates

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[78] The imputed "willingness to pay" of 50 cents per Mcf is the lowest conceivable final delivery price for gas for which there is excess demand. This is an indication of the marginal value to the final consumer.

[79] Estimates of these losses from litigation are shown in the previous chapter.

suggesting the amount of such costs at the present time, but it should be possible to trace relative industrial development in the next ten years to assess these costs in Texas, Oklahoma, and Louisiana. Second, the area rate proceedings themselves have set precedents for unmanageability of the Commission decision-making process. The first case began in December of 1960, on review of the prices set by 351 companies producing in the Permian Basin of western Texas and southeastern New Mexico. Testimony and submissions were complete by late 1965, to be finally affirmed by the Supreme Court in a decision in 1968. Aside from the expenditures on litigation, this setting up of large "class actions", in which there are numerous volumes of testimony and years of consideration, sets standards for the activities of many of the independent regulatory commissions. The criteria used in making the decision in these cases have been reviewed and have been found wanting both in terms of rigorous procedure and positive economic effects on the industry being regulated. As a precedent, the rate proceeding may have similar negative effects by imitation.[80]

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[80] It is difficult to believe that the area rate proceedings were not precedents for the Federal Communications Commission's telephone rate investigation of the American Telephone and Telegraph Company. Perhaps the results in the telephone rate investigation, as well, were partly induced by the mammoth scale of the enterprise.

In sum, the roughly measurable cost of producer price regulation seems high. Regulation has induced a gas shortage of considerable dimensions, has forced lengthy and expensive administrative proceedings on a highly complex, decentralized and previously unregulated sector of the industry. And its major objective -- benefiting the home consumer -- has not been achieved. The lower prices bestowed with one hand have produced "benefits" taken away with the other by the excess demand generated from the reduced prices -- excess demand that deprives consumers of gas reserves for which they would be willing to pay.

Alternatives to Regulation of Field Prices

The arguments against continued efforts to control the prices of natural gas producers are strong: regulation is not necessary to check the market power of producers, and there is no feasible way to calculate and capture rents or windfall gains in competitive markets. Setting the prices for producers individually is not feasible. Setting area rates is administratively complex, and will of necessity produce a gas shortage. There is every reason to expect, given the judicial process firmly ingrained in the Federal Power Commission, that the ceiling prices would consistently be set so far below the long term marginal cost of exploration and development that the natural

gas shortage has to be of important size and duration. Moreover, there are other methods available for capturing rents or windfalls. Considerable rents can be captured for the public simply by setting up effective lease auctions for oil and gas drilling rights, and requiring the payment of high rates of taxation on the land owners' proceeds from these auctions. (At the present time, this is exceptionally feasible because a large proportion of potential oil and gas bearing land holdings are properties of the Federal government.)

These considerations suggest that field price regulation should be abandoned. There are many alternative ways of doing so -- even within the boundaries laid down by the Supreme Court in the Phillips Petroleum case and the subsequent cases reviewing the area rate proceedings. Regulation on grounds of controlling monopoly prices can be abandoned where Commission-sponsored economic studies show that competition is effective. The Federal Power Commission would issue certificates for new gas found to be sold under competitive conditions, and approve price increases resulting from competitive demand and cost increases. This has been justified and long advocated on grounds that "when regulation is based upon (competitive) market prices, the ends if not the means are simple, and they make economic sense."[81]

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[81] Testimony of Professor Morris A. Adelman, before the Federal Power Commission in Champlin Oil and Refining Company, et al., Docket #G-9277, p. 458 L.C. (1958).

An alternative process would be to gradually abandon setting effective ceiling prices, on the grounds that the default in meeting demand requirements is more urgent that preventing windfall gains. First of all, price ceilings could be raised on new additions to reserves by 15 to 25 cents per Mcf, and if this were not sufficient to allow most contracts to be written for lower than ceiling prices, then it might be raised a second time. The purpose of such substantial increases would be to require that all new contract prices be below the ceiling level.

Second, attempts then could be made to rationalize the structure of old prices so that they were not completely out of line with those on new contracts. The purpose would be to set stringent new limits on quantities demanded by industrial firms and householders with the "windfall" of having purchased gas under long term contract at prices close to 15 cents per Mcf. The process of transformation of both old and new prices to market clearing levels would not be "costless"; but the long term systematic costs of excess demand would eventually be reduced to zero.

There are further alternatives, including the passage of legislation exempting producers from field price controls. Many have been proposed, and a number of legislative actions have actually been attempted. Much could be said about political

feasibility, particularly with respect to reform that incidentally benefits petroleum companies, when these companies have been especially favored by the Congress and the Executive Office over the last three decades. But the main point should be adhered to: field price regulation has no economic logic, and has had highly perverse economic effects. The Courts and the Congress under such circumstances should be prepared to bring about legal reform.

3. Regulating the Profits of Gas and Electricity Companies

The function of the Federal Power Commission as "public utility" regulator has been to control the power of electricity and gas companies over the supply of services in important interstate markets. Traditionally, the Commission has set profit limits on companies transporting natural gas in interstate commerce. More recently, it has sought to control electricity prices when the electricity has been sold at wholesale across state lines.

The Federal Power Commission has not been effective at performing these classical regulatory functions. This conclusion -- that profit regulation has not limited the ability of the companies to exercise control of prices -- does not necessarily reflect discredit upon this regulatory commission. The causes of lack of effectiveness may be merely irremediable. These causes will be investigated here, in the process of establishing findings on the effectiveness of regulation.

The investigation consists of four parts. The first describes the benefits of full fledged price surveillance and enforcement as now practiced by the Commission. The task is to measure the benefits achieved by devoting considerable time and effort at the Commission level to individual price cases and at the staff level to widespread price surveillance. The

second part describes price regulation. The third part attempts to determine the extent to which the system of price controls (by profit limitation) has led to lower prices in actual markets. This is to bring evidence to bear on the question of whether, and to what extent, prices and profits would rise if companies were legally free to set them without regulation. Finally, the fourth part provides an overall assessment of the present status of F.P.C. regulation, and considers the possibility of reform -- that is, possible alternative methods for regulating prices that would retain the benefits of the present system at lower administrative costs.

The Benefits of Full-Fledged Enforcement

The primary task of Commission regulation is to keep the profits of the public utility company low -- at or close to that amount sufficient to attract capital into a competitive market in which firms are faced with comparable risks of survival. Whether regulation has in fact accomplished this is a much debated question. On the one side, it is alleged that regulated firms can convince Commissions to allow them to earn close to the rate of profit that would prevail in the absence of regulation (under non-competitive conditions). On the other side, it is claimed that regulated firms' profit rates are considerably lower than they would be without regulation in

that industry. An analysis has to be undertaken to establish evidence for one side or the other.

There are two basic ways in which regulation might operate to lower the prices of the public utility company. First, the mere presence of a commission with the power to limit prices might inhibit a firm's tendencies to charge monopoly or oligopoly prices -- even if the commission makes little effort to investigate rates thoroughly or to enforce general controls. The power of the commission to set legal limits on profits or prices, and the willingness to proceed against "outrageously high" prices, may act as a check upon pricing policy even if no cases are actually heard. Second, the commission's activities in bringing proceedings against companies to require them to lower their prices, or not to increase their prices, may lead to prices that are not only lower than what the company would charge without regulation but that are also lower than what the company in fact proposes under regulation. The defender of regulation would claim that the "price savings" brought about by the regulatory process of cases and surveillance amount to the difference between the allowed price and the firm's "desired price" (which it would charge without regulation). The defender usually recognizes, however, that because of the great difficulty of measuring the "desired price" the amount of the savings is indeterminate insofar as it exceeds the firm's proposed price.

The most ardent defender of regulation is the Federal Power Commission itself. The benefits proposed by the Commission to have followed from regulation in recent years are measured in terms of these savings. This section will deal with the *tangible* proportion of the saving, as the difference between actual and proposed prices under regulation. The question is what is the extent of the saving, and to what extent does any such saving represent economic or social measures of benefits from regulation. The third section extends beyond these measures to a first attempt to find the more speculative portion of the savings, the difference between the present allowed prices and those that would exist without any regulation whatsoever.

The Commission's estimates of price reduction benefits can be put together from claims as to the amount of the difference between the regulated firms' proposed prices and the actual allowed prices as a result of annual regulatory proceedings. The 1968 *Federal Power Commission Annual Report* announced that during the last fiscal year, "reductions in wholesale rates of electric power moving in interstate commerce and subject to the Commission's jurisdiction amounted to $8,860,595, the largest total for a single year in the Commission's history .... While many rate filings were submitted by the utilities on their own initiative,

nearly 70 percent of the total dollars of rate decreases were the result of Commission action...."[1] The proposed price increases withdrawn by the companies resulted in dollar amounts of rate payments that were eliminated rather than incurred by the consumers. The Commission counts these dollar savings as benefits, flowing from its administrative activities in regulating power companies' prices and profits.

The Federal Power Commission claims similar benefits from reduced gas consumer prices as a result of pipeline rate investigations. The Annual Report for 1968 states that "of ten major proposals to increase [pipeline] rates by a total of $63,380,200 annually ... one proposal, involving $2,687,100 annually was rejected and two involving $95,400 annually were accepted without suspension...."[2] Another $12 million of rate increases proposed in earlier years were disallowed or withdrawn by the companies in Commission proceedings that year, and there were $13.9 million in rate reductions required of the pipelines after F.P.C. surveillance reviews of selected rates. The Commission actions in the gas pipeline industry resulted in $28 million of rate reductions which accrued to the individual consumers of natural gas.

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[1] Cf. The 1968 Annual Report of the Federal Power Commission, U.S. Government Printing Office (Washington, D.C., 1969), p. 19.

[2] Ibid., p. 59.

These reductions overstate the "tangible" social benefits of F.P.C. regulation for two important reasons. First, some consumers see rate reductions as increases in their income, but other consumers who are stockholders in gas and electricity companies see rate reductions as income losses (from reductions in their dividends). The first group's income gains are to some extent counterbalanced by the second group's losses. This dollar amount, shown as area "A" in Figure 1 in the first chapter, represents a social gain only insofar as income distribution after the rate reduction is more "socially acceptable" than the distribution before the reduction.[3] And, of course, the value of one or another income distribution is a matter on which judgments greatly differ. Only the "quantity" increases generated by lower prices can be considered as net social gains. The extra consumption generated by the price reduction, shown as area "B" in Figure 1, can produce net gains for both groups, as consumers gain additional output of gas or electricity while producers do not lose output.[4]

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[3] There is no a priori reason to favor the consumers' income over that of stockholders, because there is no theory establishing the general equity of such redistribution. In fact, there is no theory implying that such redistribution makes incomes more equal; rather, this is an empirical matter.

[4] This is the case if area "B" is net of the cost of supplying the additional consumption, even though the "cost of service" as defined in public utility regulation does not show whether this is the case.

Second, the extent to which the F.P.C. is in fact responsible for the listed price reductions -- even those from proposed, to actual, prices -- is often unclear. Some reductions might have taken place in the absence of regulation, purely as a result of the best-profit reaction to cost reductions. Monopolists reduce prices when new scale effects are felt in cost reductions, or when factor prices decline as a result of technical progress, or when there has been substantial entry of other companies on geographical or product fringes of markets. Both the gas and electricity industries enjoy large scale economies in systems, and the electricity industry at least achieved substantial cost reductions in the 1960's from input price reductions.[5] Moreover, companies in each industry face increased competition from those in the other industry and also from coal and oil in industrial markets for energy. Some companies may have been willing to reduce rates or to withdraw proposed rate increases, for these reasons and yet credit the results to vigorous regulation by the Commission.

Because of these difficulties, the F.P.C.'s estimates of benefits must be scaled down. Even the scaled down estimates can be treated only as rough indications of the maximum amount

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[5] Cf. P. MacAvoy and J. Sloss, Regulation of Transport Innovation: Unit Trainloads of Coal to the Eastern Seaboard, Random House (New York, 1966), and P. MacAvoy, Economic Strategy for Developing Nuclear Breeder Reactors, Appendices A and C., The M.I.T. Press (Cambridge, Mass., 1969).

of tangible benefits that a fairly strict case system and surveillance procedure can produce.

The tangible benefits of electric power regulation. Although the Commission announced that there were $8.9 million of electricity price reductions related to regulation in the 1967-1968 fiscal year, they claimed that only 70 percent of this amount resulted from the cases and from rate surveillance. Thus, the F.P.C. claimed tangible benefits from regulation of $6.2 million in that year. In fact, however, this figure must be adjusted for arriving at even a maximum estimate of economic benefits, to take account of the effects from income redistribution. A very rough effort to do so begins with dividing electricity buyers into two groups: industrial and residential. Industrial (and commercial) firms buying electricity gain in income roughly what electricity producers lose. The saving to consumers results in lower production costs for these firms, which are ultimately passed on either in dividends to shareholders or in lower final product prices to consumers. In fact, these firms most likely pass on most of the savings to shareholders, not customers, since they are firms in highly concentrated industries noted for high price-cost margins so that they are not likely to feel forced by competition to pass the benefits of

lower costs on to customers.[6] When buying firms' shareholders benefit at the expense of electricity shareholders, there is no net economic benefit: income has not been redistributed more equitably on any account. Since about 55 percent of all rate reductions went to industrial or commercial buyers, this $6.2 million estimate must be discounted by at least 25 percent.[7]

Final consumers of electricity, in contrast to industrial consumers, could gain more from price reductions than the owners of the electricity companies lose. This would occur on the assumption that final consumers are poorer than shareholders and that it is socially desirable to transfer dollars from the rich to the poor. Although economists balk at efforts to measure the value of transfering a dollar from one man to another, regulatory commissions, governments, and even private businesses make decisions on the basis of assumptions about such a value. In fact, government tax policy represents such a social judgment about the worth of dollars in the hands of members of different income classes. That is to say, tax policy that takes 70 cents

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[6] According to the Census Bureau [U.S. Bureau of the Census, Census of Manufactures, 1963, U.S. Government Printing Office (Washington, D.C., 1966)], the four largest consuming industries were primary metals, chemicals, petroleum, and stone-clay-glass. The four-digit concentration ratios in these industries were 56.1, 49.3, 36.7, 37.1 percent respectively [Concentration Ratios in Manufacturing Industry, 1963 (1966)]; they are all higher than the all-industries average of 32 percent.

[7] This assumes that about one-half of all rate reductions to commercial or industrial firms were passed on to consumers -- a very generous assumption.

away from each dollar earned by a rich man and 20 cents from each dollar earned by a poor man suggests the judgment that a dollar transfer would increase the value of total income by 40 cents. Since average Federal taxes paid by the consumers are lower than those paid by shareholders, it would appear that the worth of price reductions is substantial; any amount passed directly from producer to consumer should be treated as worth at least what the consumer could keep if he received it in the form of income -- on average, approximately 80 cents -- while the value of dividends lost would be the amount remaining to the shareholder after taxes -- an average of 30 cents.[8]

The "social value" of transferring a dollar from shareholder to consumer is, on this theory, 50 cents. In the hands of the consumer, a dollar of income or its equivalent might be thought to be worth 80 cents after taxes. Of this 80 cents, 30 cents comes from income foregone after taxes by the electricity company stockholder.[9]

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[8] That is, the direct transfer from the net income of the dividend receiver to the rate payer would be $1.00 minus taxes, or $1.00 - (1.00)T - (1.00)Tt, where T is the Federal income tax rate on corporate profits, and t is the rate on dividends paid from after-tax profits.

[9] The average income of all stockholders is estimated to be $108,000 per year. This income is from weighting incomes shown in the U.S. Department of the Treasury's Statistics of Income (U.S. Government Printing Office, Washington, D.C., appropriate years) for 1967 (Individual Returns) by the amount of dividends received. The average aggregate tax rate on this income, given personal deductions allowed in a four-person family, cannot exceed 40 percent. Then the implied rate of taxation on $1.00 of pre-tax dividend income of an electric generating company is 50 percent on corporate and 20 percent on personal tax (or 40 percent on the remaining after-corporate-tax 50 percent).

The amended estimate of income gains in the \$6.2 million is \$2.3 million.[10] This estimate follows from reducing the gross figure by 25 percent for direct industrial sales benefitting the buying companies' stockholders, and then reducing the remainder by 50 percent to account for the net gains of consumers against stockholders. The resulting estimate must cover all of the conceivable gains that a society can make from using the regulatory commission as a mechanism for transferring income.

There are additional gains because of quantity increases generated by the rate reductions (shown as area "B" in Figure 1). The maximum estimate of this surplus, illustrated graphically, is the area $(\Delta P \Delta Q)/2$ for the regulated-induced price reduction ΔP and the regulated increase in quantity demanded ΔQ. The Commission reports do not estimate the rate reductions, nor their effects on quantity demanded. But they can roughly be approximated from public information on revenues and sales.

The Commission tells us that rate reductions in the important cases in 1968 ranged from 5 percent to 9 percent of total receipts, so that the average percentage reduction $(\Delta P)Q/(PQ)$ is assumed here to be 7 percent. Other sources of information

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[10] This is 50 percent of the total sales accounted for by home consumers and by consumers of industrial goods with lower prices (because of lower electricity prices). The calculation makes one further stringent assumption. The 70¢ on the dollar given up by the stockholder comes from his taxes, and it is assumed that the Federal government has no opportunity loss from this diversion of income. This may be roughly correct, given the small amounts diverted from other uses of tax funds.

provide indications of demand elasticity $P\Delta Q/Q\Delta P$. The elasticity estimates in detailed econometric studies have ranged from -0.2 in the high income Northeast states to -0.7 in the Southern states for home consumption of electricity. Industrial demand studies have indicated elasticities of -1.0 in 10 large using industries.[11] A less exact but more current overall estimate of elasticity is -1.2.[12] These indicators can be used to find the gains in consumer surplus from the 1968 rate reductions -- multiplying the elasticity estimate by the percentage reduction provides an estimate of ΔQ and this, along with the Commission's announced reductions of \$6.2 million, provides an estimate of $\Delta P \Delta Q/2$ of \$260,000.[13] The quantity increase benefits from one year's electricity

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[11] See F.M. Fisher and C. Kaysen, *A Study in Econometrics: the Demand for Electricity in the United States*, North Holland Publishing Co. (Amsterdam, 1962), pp. 42,50,135. These are averages over states and industries, roughly in accordance with the amount of electricity consumed.

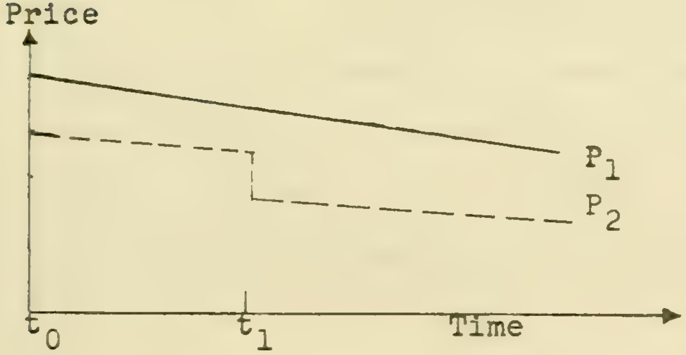
[12] See P. MacAvoy, *Economic Strategy for Developing Nuclear Breeder Reactors*, *op. cit.*, Appendix C, "Documentation of Forecasts." The elasticity is for price of electricity effects on the demand for generating capacity, and this is a long-run elasticity.

[13] The calculacion procedure is straightforward. There are three pieces of information: (a) $(\Delta P)(Q) = -(6.2)(10^6)$; (b) $(\Delta P)Q/PQ = -0.07$; and (c) $P\Delta Q = -1.2Q\Delta P$ assuming that the elasticity of final demand is -1.2. From (b) and (c), $-P\Delta Q/PQ = -0.084$ or $Q = \Delta Q/0.084$. Substituting this expression for Q in (a), then $(\Delta P)(\Delta Q) = -(6.2)(10^6)(0.084)$ and one-half of this amount constitutes a first estimate of consumers' surplus.

regulation are not much more than one-quarter million dollars.

On the other hand, the total annual benefits of both income transfer and consumers' surplus, once generated by Commission action, should last more than a single year. The company cannot propose exactly the same rate increase in the next year, given that cost and demand conditions are exactly the same, and expect to be rewarded with any result other than an exact replication of this year's decision. But over a period of two or more years, cost and demand conditions may change significantly, so that new submittals to the Commission could be made and new decisions on the proper level of rates arrived at. Also, surveillance activities would have to be "renewed" because changes in costs would vitiate the value of the results gained from the first surveillance analysis. In Figure 2, to give an example, a review of rates completed at time T_0 resulted in a price reduction from P_1 to P_2; both P_1 and P_2 gradually fall over time because increases in productivity in this industry

Figure 2



exceed the average productivity increase in the economy. P_2, however, falls more slowly than P_1 since it is a maximum or ceiling price set by Commission review below the profit-maximizing level. By time t_1, the effects of the rate review have mostly worn off, at which point a new review should take place. It is a judgment of lawyers defending clients before the Commission, and staff members of the Federal Power Commission, that the length of time before serious erosion occurs would be at most five years. Taking this lag into account, the total tangible benefits from surveillance and rate review activities during a single year equal at most the present value of five years of price reduction. The present value of income benefits of type "A" is \$2.5 million and of quantity type "B" is \$0.3 million.

These amounts would seem to be a maximum estimate of tangible benefits. Actual values may in fact be much less, because these amounts do not take into account possible losses caused by forcing some prices below costs. Since the Commission often asks for relatively small price reductions, while the cost of litigating a Commission demand is large, companies may be tempted to give in to the Commission even when the proposed reduction is below costs on some service (in Northern States Power Company, Docket E-7140, for example, the Commission asked

for $254,468 of rate reductions. It argued that the company's "costs of service" amounted to $3.486 million, while the company claimed its costs were $4.653 million. Rather than litigate, the company chose to concede the reduction "without prejudice to its contentions" and the Federal Power Commission found this "an acceptable compromise of contested issues involving numerous judgmental factors").

Moreover, as previously mentioned, some of the Commission-induced reductions might have occurred anyway. One company president said in response to requests for estimates of the costs of regulation, "In the middle 1960's the Federal Power Commission for the first time asserted jurisdiction over the sales by electric utility companies to local distribution systems.... Although the Commission's jurisdiction had been defined by statute in 1935, the Commission under Chairmen Swidler and White greatly extended the concept of what constituted an interstate sale. In most states these wholesale rates had been regulated by the state commissions for many years.... Many state commissions still assert duplicate jurisdiction over such sales...." With duplicate regulation, some rate reductions occur as a result of the activities of state commissions. These reductions would

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[14] Private correspondence initiated by P. MacAvoy.

show as part of the gains from national regulation and are thus incorrectly counted.

Last of all, it is quite possible that the results overstate benefits because price reductions have been lower and consumer demand less responsive to these reductions than has been assumed. In fact, if price reductions were less than 5 percent, and if the value of price elasticity was -0.2 (as found by Kaysen and Fisher for home consumers in high income states), the estimated consumers' surplus "B" from regulation would have been approximately zero. A more cautious view of benefits would restrict the amount to that from area "A" for a two year period before the decay of the difference between regulated and unregulated prices; such an amount would equal only $1.9 million.

The tangible economic benefits from natural gas pipeline regulation. Regulation of the pipelines has had the effect of reducing some prices. The amounts of the price reductions, recorded as "benefits", were probably greater than those associated with regulation of electric power prices. But the analysis of the benefits and the method of adjusting the Commission's claim so as to produce a reasonable maximum figure is similar to what has just been done in the case of electricity.

The Commission disallowed \$2.7 million of price increases proposed during the 1968 fiscal year as well as \$12.0 million of previously proposed increases.[15] The F.P.C. was responsible in some part for \$13.9 million of rate reductions that year and larger amounts in previous years which were "in large part the flow-through of supplier refunds and rate reductions (from natural gas field price regulation)"[16]. Even assuming, contrary to what was probably the case, that these firms would not have reduced prices because of cost reductions, the Commission's regulation could be credited with only the first and second reductions; the third has to be properly attributed to field price regulation. Moreover, the first and second figures must still be adjusted, for they are gross gains of rate payers, not net gains to all participants in the transfer of income from dividend receivers to rate payers.

The net gains from distributing \$14.7 million of potential stockholders' income to consumers must first be reduced to take into account the fact that they flowed from disallowed price increases, not price reductions. The F.P.C. measured total dollars gained by taking the old quantity of gas Q_2 and multiplying that amount by the increased price P_1, then subtracting the same quantity

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[15] See the F.P.C. 1968 Annual Report, *op. cit.*, p. 59.

[16] *Ibid.*, p. 60.

Q_2 multiplied by the reduced price P_2. Such a measurement is wrong, for it would count as gain a certain amount of payment $(P_2 - P_1)(Q_2 - Q_1)/2$ that would not in fact have been made at the higher price because there would not have been this amount of gas demanded at the higher price. Subtracting an amount for non-existent demand (equal to \$1.9 million)[17] from the \$14.7 million produces an estimate of gross income gains "A" plus net gains "B". The gross income "A" (equal to \$10.9 million) must be further reduced in the same way that gains were reduced in the case of electricity. First, approximately 65 percent of final demand is attributable to industrial consumers. And, as in the case of electricity, only 50 percent of any redistribution from electricity company stockholders to buying company stockholders could be perceived as a net social income distribution gain. On this assumption, one year's "A" type benefits from reduced prices on industrial sales would amount to \$3.54 million. Second, the gains to final consumers from direct retail utility sales would again be approximately one-half the amount of the total dollar reduction in rates (given that 50 cents on

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[17] This calculation proceeds in exactly the same fashion as those for finding consumers' surplus from electricity rate reductions. Given that $(\Delta P)(Q) = \$14.69$ million, $\Delta P/P = 10$ percent, and the elasticity of demand is -1.28 as shown by the econometric demand relations for gas described above, then $\Delta P \Delta Q/2 = (-0.10P)(-1.28\ QP/P) = (-0.10)(-1.28\ \Delta P \cdot Q) = \$1.88$ million.

every dollar of additional consumer income from lower prices would have to be "attributed" to losses of others in society). These consumers' gains are estimated to be $1.9 million, and total "A" type benefits to be $5.5 million. Adding the "B" type benefits of $1.8 million, the total consumers' benefits in one year probably amounted to $7.3 million. One year's regulation could have produced at most 5 years of benefits of this nature; if so, the present value of this year's activities in setting rates for natural gas pipeline companies would have been $7.8 million -- $5.9 million for "quantity-increasing" "B" type regulation and $ 1.9 million for "income-redistributing" "A" type effects.

Conclusion. The analysis in this section suggests that a maximum estimate of the tangible economic benefits of the Commission's casework and price surveillance amounts to about $10.5 million annually. Almost all of this benefit consists of transferring income from stockholders to consumers. And, a high value has to be placed upon such transfers in order to reach the $10.5 million figure.

Against these benefits must be put the costs of regulation. As shown in the first chapter, the administrative costs required to produce these dollars of transfer have amounted to nearly $9.2

million in a typical year in the 1960's -- in a sense, an overhead of more than 87 percent on benefits.

These estimates raise two questions. Since most of the benefits consist of income transfer, could not the tax system perform the same job more cheaply? The administrative expenses involved in redistributing income through taxes are only a small fraction of the more than 87 percent required for transfer by means of regulation. In any event, could most of these benefits be achieved more cheaply by cutting the costs of regulatory administration? Instead of bringing so many cases, and spending this amount of dollars on surveillance, might not the Commission have achieved benefits of nearly the same magnitude by setting rules on allowable costs and profits in an occasional case, and trying to develop mechanisms for self-enforcement?

Answering these questions requires analysis and testaments of the effects of reduced regulation. The first step is to assess whether the regulated firms ask for and are required to charge significantly lower prices than would occur in the absence of any Commission regulation. The assessment depends critically on the standards used by the Commission to limit profits in its full scale landmark case reviews. We must look at the way in which the Commission has determined the proper rate of return on capital investment in electricity generation and pipeline transmission. We can then attempt to determine whether the Commission's regulation has produced economic benefits other than the tangible benefits just described.

Landmark Case Decisions on Profits of Utility Companies

The process of regulation by the Federal Power Commission -- the mechanisms for establishing rules to be applied to all of the annual rate submittals -- can be distinguished from the on-going surveillance activities of the Commission and staff. Rules have been set out in elaborate terms, in a number of Supreme Court decisions rendered since 1940, for the purpose of controlling the collection of information and the disposition of issues that are behind the huge volume of day-to-day activities. These rules have been justified as focusing activities, both of the staff of the Commission and the defendents in cases brought by or before the Commission. They provide focus, in the sense that certain activities may be disallowed altogether or that specific aspects of other activities are designated to become matters of controversy. To be specific, the procedures used by the Commission focus issues related to profits on setting legal limits on the average rate of return on capital expenditures, and on the accounting definition of capital expenditures.

The question is whether the process itself results in closer achievement of the original goals of regulation than would some possible alternative process. This is not the same as asking whether the day-to-day surveillance activities are "unduly extended." The precedent Commission or Court decisions may have widespread effects without any surveillance activities by the Commission staff, because the companies themselves may be required to conform to the precedents by market circumstances or by threats of suits by customers. For example, a limit on the average rate of return for Company A may become applicable to Company B without Commission surveillance, because Company B

has to apply to the Commission to raise prices to make this amount, or because Company B's customers apply for lower prices so that the returns are reduced to this level. A small number of Commission decisions each year, accompanied by economic conditions requiring case decisions for many other companies, may be sufficient to establish systematic effects from regulation.

This makes the question much more basic than that as to the results of surveillance. The case decisions, and the rules evolving from these decisions over time, could have the effect of establishing prices for industrial and residential sales of gas and electricity which were close to the costs of providing for the sales. Such results would generally be considered to be in the direction of setting "just and reasonable" prices according to the original legislation. They might well be more in that direction than prices from some alternative set of (administrative) procedures or (Commission) decisions. But these results do not follow as a matter of course: there are circumstances in which the prices under these regulatory norms could be set as high as unregulated market prices. This makes the question whether the price and sale performance of the companies under regulation indicates gains for final consumers of gas or electricity.

To begin the search for an answer, the process itself has to be described. This is no simple matter, because important elements have not been formalized but have become "accustomed ways of carrying out regulation." The formal aspects, rendered in great detail in the development of the concept of "cost of service," will be described first. After this has been done in the next section, the less formal aspects will be dealt with -- those related to choosing the "economic facts" within the process so as to prescribe limits on profits. These sections will provide a basis for defining what is to be assessed, and the subsequent section will show the effects of regulation of this kind on profits, prices, and outputs. The assessment leads to a consideration of the alternatives -- either of eliminating profit regulation entirely, or of developing a new form of regulation that is both politically practical and has better results.

The Cost of Service Approach to Profit Regulation

The *Federal Power Act* of 1935 and the *Natural Gas Act* of 1938 provided the Federal Power Commission with the statutory authority to set limits on the prices of natural gas and electricity sold at wholesale in interstate commerce. The statutes made it necessary for the producing or transporting company to request price investigations by the Commission or to complain before the Commission if they believed that prices were too

high. The basis for claims has been the phrase in the statutes requiring that prices or "rates" had to be "just and reasonable" and could not be "unduly discriminatory." These words have been interpreted by successive Federal Power Commissions, and the interpretations affirmed by the Supreme Court, so as to require a particular procedure for finding "reasonableness." The procedure has been termed the cost of service method.

According to this method, the prices to be charged by the transporting or generating company are those that result in total revenues just sufficient to cover the total costs of providing service. The costs of service are the total of operating and maintenance expenses, purchased raw material costs, taxes including Federal and State income taxes, depreciation of investment, and a fair rate of return on the undepreciated portion of investment. The exact amount of each of these costs is the matter at issue between producers, Federal Power Commission, and buyers.

The first delineation of cost of service was provided in Natural Gas Pipeline Company of America (2 F.P.C. 218) in 1940 and the most elaborate definition and specification was provided in the landmark case of Hope Natural Gas Company (3 F.P.C. 9150)in 1942. These showed the general outlines of the approach, and also anticipated that certain aspects of cost finding would become quite routine while other aspects would be the center of controversy. The calculation of operation expenses, raw material

costs and depreciation or depletion have been worked out between accountants in the companies and those on the staff of the Federal Power Commission. The calculation of the proper level for Federal and State income taxes has been a matter of controversy only because the Internal Revenue Service and the courts have allowed regulated firms to use one method of tax accounting for price setting purposes and other methods for purposes of determining proper payments to the Government. The areas of dispute between company and Commission have been the calculation of the allowed limit on the average rate of return on capital, and of the total amount of capital.

The reasons for centering attention on "rate of return" and "rate base" (the undepreciated portion of original investment) are that specific statute definitions of these categories of cost have not been established. The operating and raw material costs of providing electricity can be defined in terms that allow accountants or engineers to specify dollar expenditures with very little variation. The costs of depreciation have been defined by the Commission as "the loss in service value not restored by current maintenance incurred in connection with the consumption of plant in the course of service" (F.P.C. Uniform System of Accounts, p. 1). In practice, the staff and company defendents have accounted for the amount of depreciation by multiplying the original cost of capital equipment by a fixed percentage that would reduce the expenditure to salvage value at

the end of the useful life of the plant. If the plant, for example, were to last twenty-five years the annual depreciation charge would be four percent of the difference between the original cost and salvage value. These are matters of legal decree, as are the periods over which the previous costs are to be calculated for price setting purposes.

But the "fair rate of return" remains to be defined by statute or by case decisions. The Courts have emphasized that the return has to be high enough to preserve the financial health of the company, to provide incentives for management to become more efficient, and should not penalize earlier investors. In the absolute, this could be done by allowing the company to earn monopoly rates of return, and by limiting entry through restrictive certification so that the regulated firm does achieve what it is allowed. To the contrary, further proceedings have stated that the rate of return should be "equal to that being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties" (Bluefield Waterworks and Improvement Company vs. Public Service Company of West Virginia, 262 U.S. 679); this standard would hold rates of return to the level of opportunity costs, or to the marginal rate of return on the alternative (competitive) investment. It would not seem to be possible to meet all these standards at once, at least not in a way that made for consistent

estimates of the rate from from analyst to analyst. Rather, conflicting "rules" or "standards" for finding the elements of interest and profit returns make it necessary to provide weightings to achieve a limit or target return. In the words of the Court, "what annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment ...." (Bluefield Waterworks, op. cit.).

The critical issues arise with finding rate base and rate of return for a second reason -- because slight variations in estimates of these cost components could conceivably lead to substantial differences in final prices. The rate and the base are multiplicative, and may form more than half the cost of service. A very small change -- less than 1 percentage point -- in the rate of return could conceivably change the average price by 10 percent, while an error of the same size in the calculation of the rate base would affect price by a lesser but still significant percentage.[1]

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[1] The elasticity of price with respect to the rate of return is equal to profit returns as a percentage of gross revenues. If this rate is increased from five to six percent, while capital returns are fifty percent of gross receipts, then prices could increase as much as ten percent. The elasticity of price with respect to the rate base is equal to the gross receipts on undepreciated capital as a percentage of total sales revenues. If an error in determining rate base were as large as ten percent of the rate base, then, with profits and interest on undepreciated capital at seventy percent of gross revenues, prices might be distorted by as much as seven percent. The simultaneous occurrences of these two mistakes would increase prices by 18 percen

The problems, and the importance of specification of procedures for solving them, were recognized at an early stage in F.P.C. profit regulation. The Supreme Court in F.P.C. versus Hope Natural Gas Company (320 U.S. 591) during its 1944 term noted that Congress had "provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in details of the general prescription ...." As a result, this is left to the Commission; but the F.P.C. itself was not bound to provide a formula either. In this regard, the Court said that "the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate making function, moreover, involves the making of 'pragmatic adjustments.'" Any procedure would be acceptable, as long as the results appear acceptable to the judges on Court review: "Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling."

Recognition of the problem, however, has not been sufficient to result in a systematic procedure for calculating rate and base. The F.P.C. has classified information, and "considered" information in each class as "relevant," if only because failure to do so might result in reversal of a decision by the Courts. This is because the Supreme Court in the Hope case, while looking only to results, described them in terms that could be used to classify indicators of acceptable rates. The Court said that "the return to the equity owner should be commensurate with

returns on investments having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise .... to maintain credit and attract capital." From the phrases "comparable returns," "financial integrity of the enterprise," and "capital attraction," have evolved at best a series of substantive classes of information, or at least a series of topics to be discussed in rate hearings.

The extent of the development of formalism can be seen by reviewing a rate case. Here we shall review the 1958 docket G-3123 involving rate of return and rate base for the Natural Gas Pipeline Company of America (19 F.P.C. 1005), because of the presence of most aspects of F.P.C. procedures and of a rather more full or more complete rendering of the process in the written opinion. The Commission dealt first with the purpose of rate control: "the primary aim of the Natural Gas Act is to guard the consumer against excessive rates" (at 1006) and then proposed to see whether a settlement between the pipeline and its customers on proposed rate increases was "fair, reasonable, and in the public interest." The investigation was necessary, of course, since the settlement was very likely based on what the buyers and the seller thought the Commission would approve; an F.P.C. position of "no investigation at all" would likely be forecast and result in settlement at the monopoly price. The approach was to quote Hope Natural Gas on "the legitimate concern with the financial integrity of the company" and then

compare the settlement with findings of an examiner. The settlement was to be preferred because the examiner's rates of return were too low: "we have never allowed rates of return of this magnitude to seasoned natural gas companies and under these circumstnaces it is of greater benefit to the consumers that Natural's financial integrity be assured, its credit maintained, ... rather than the consumers be recipients of a temporary gain" (at 1007, 1008). The examiner had adopted "test year" data for operating expenses, maintenance expenses, and the undepreciated portion of original costs of investment; testimony in the record had dealt with "comparable earnings" of investors from providing funds to this and other companies with comparable risk, and had dealt in detail with the previous levels of earnings of Natural Gas Pipeline. Thus, the F.P.C. decision weighed information on these aspects against its impression of "low" and "high" historical rates. The additional factor was agreement of buyers and the seller on a "reasonable" rate of return.

The Federal Power Commission's use of standards in finding rate base and rate of return has been almost imperceptible. Later case decisions have mentioned data on other than the previous history of rates of return; for example, in the Northern Natural Gas decision in 1961 (25 F.P.C. 431), the Commission said that "the most pertinent index is a comparison of recent earnings price ratios of the major pipelines, considered

in relation to return on book value of common stock and variations in the business risks and advantages of the individual companies" (at 444). But nowhere are weights given explicitly to these obscure and sometimes contradictory factors in arriving at a single estimate of the reasonable rate of return. The highest degree of formalism begins with "determining the cost of the company's debt and of its preferred stock, by making an allowance for its common equity based upon earnings price ratios and other factors, and by applying these amounts to the company's capitalization so as to arrive at a rate of return" (El Paso Natural Gas Company, 28 F.P.C. 688, at 691; decided in 1962). Even here the weights on "other than E/P ratios" are not given; and the Commission goes on to say that "to use this approach alone .... places too great an emphasis on the exact percentage of the equity ratio .... therefore we think it important and realistic also to consider the end result" (at 691).

There has been no recent progress towards discernable standards. There were 29 cases on prices, profits, and rates of return set out in the most recent full volume of Commission decisions (1969-1970), 22 resulting in findings in favor of the pipeline company, and 7 against. There were also 27 cases on motions relating to previous rate of return cases, 9 of which were granted and 18 of which were denied by the Commissioners. All of the cases on motions were inconsequential, since they

did no more than once again finalize previous decisions. Most of the rate cases themselves were not concerned with limits on the rate of return, but rather with the necessity of hearings on new schedules,[2] or with refunds possibly resulting from other proceedings.[3] Very little of what the Commissioners did here was important, in the sense of affecting prices.

There was one case in which the Commissioners completed a full review of the rate of return of a large gas pipeline and then allowed this return to go to 7.25 percent, the highest level permitted in the 1960's. Florida Gas Transmission proposed higher prices on all its regulated sales in August of 1968, and the F.P.C. suspended them until February of 1969, when they became effective subject to refunds. The F.P.C. staff made a presentation of evidence on rate of return that appeared to justify lower prices. The evidence was based on actual costs of debt interest in the review or "locked-in" period from June, 1968 to February, 1969, and also on actual rates of return on equity of "comparable" companies in the same period. These actual rates were supposed to show the opportunity costs of investors -- if they did not receive

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[2] Mississippi River Transmission Corporation, 42 F.P.C. 272.

[3] Consolidated Gas Supply Corporation, 42 F.P.C. 325.

comparable interest and comparable profit rates from the Florida company in the future, then they would withdraw their capital from this firm. But the Commissioners did not accept the highly standard methods used for these staff calculations -- "We have repeatedly stated that the relative weight to be given the varying factors (in rate of return) does not lend itself to precise mathematical determination"[4] -- nor did they agree with the final rate estimates of the company. Given a choice of 7.50 percent return from the company's economic witness, or the staff's recommendation of 7.0 percent, the Commission found the return of 7.25 percent to be "the fair and reasonable rate of return."

What were the Commissioners doing in this case? Formally, they applied the proposition that historical costs equalled future costs for pricing purposes, whether the historical costs were those of Florida Gas or of "comparable" companies. The focus was on "the higher imbedded debt cost during the (latest) two docket periods" and "a slightly higher rate on equity which we believe is justified in the light of the shift in capital from 64.46 percent debt as of the time of RP 66-4 to 71.73 percent in the (latest) docket."[5] The rate on equity was also justified on grounds that it was lower than in "the three most recently contested cases determining

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[4] 42 F.P.C., at 83.

[5] 42 F.P.C. 89.

rate of return before this Commission."[6] There is no economic reasoning supporting this procedure -- the costs of using resources are not historical costs. The justification is that historical costs produce forecasts that have the right results; in the Commission's own terms, "consideration of the evidence in this record and particularly the Company's own evaluation of its accomplishment over the nine-year period of its existence leaves little doubt that it has made tremendous strides in growth of physical plant and average daily throughput, made impressive increase in earnings, and secured adequate financing on the rates of return we have allowed."[7] Thus, the most recent indicators have been that the company "does well," in a qualitative sense.

There have been severe conceptual problems in finding the rate base, as well. Only part of the business has been regulated, because F.P.C. jurisdiction is limited to "sales for resale in interstate commerce"; since this legalism excludes direct pipeline sales to industrial buyers but includes sales to retail gas distributing companies, joint capital costs for the two categories of service have to be divided to find the rate base for regulated sales alone. Accurate and efficient methods for dividing up the joint costs on installed transmission lines have not been developed by engineers and economists, so that they could scarcely be an integral part of the regulatory process. Even so, the methods used have

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[6] 42 F.P.C. 88.

[7] 42 F.P.C. 88.

been general and vague because of case-by-case inconsistencies. The controversial Atlantic Seaboard Formula imposed costs on unregulated sales -- whether or not they could be covered by returns in "competitive" industrial fuel markets -- that should have reduced accounting costs on regulated sales and ultimately reduced regulated prices.[8] But the Formula has been "tilted" every which way in case decisions during the last decade, so that by 1968 it no longer applied even on the Atlantic Seaboard Pipeline Company itself.[9] The theoretical and practical problems might have been overwhelming: the regulators dealt in an inconsistent fashion, with no consequent effects on "costs of service" and ultimately prices.

The question here is what are the Commissioners' standards now for making decisions, and for determining whether the results of their decisions are favorable? Placing emphasis on an "impressive increase in earnings" would suggest that the Commissioners have been striving for maximum profits for Florida Gas, while greater emphasis on "growth of physical plant and average daily throughput" would, to the contrary, imply that they have been seeking to maximize the final consumers' gains from sales. The invocation of both as desirable obscures evaluation of the

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[8] More precisely, the Formula reduced costs allocated to peak-load service, relative to off-peak service, when compared to costs allocated on a volume basis. If peak-load service -- that on the three days of the year of greatest demand -- was entirely for retail utility buyers, then costs for this favored group would be reduced.

[9] Cf. Atlantic Seaboard v. F.P.C. 404 F 2nd 1268 (1968) and the detailed discussion in A. E. Kahn, The Economics of Regulation (Wiley, 1970) Vol. 1, p. 99.

Commissioners' procedures. The only possibility is to assume that the Commissioners know what they are doing, despite espousal of contradictory results, and that they have decided on the rate of return that best achieves their goals. If this is conceivable, then an examination of the promised return is the only way to show their reasons and their methods.

The Regulated Rate of Return

The allowed limits on rates and rate base can be assumed to reflect the purpose or intent of the Commission. The process of decision making may not be revealed by the cases, because of the dominant element of judgment by the Commissioners of "reasonableness"; but the process is revealed by the systematic results. If rates of return are "low," then the evidence is sorted so as to prevent consumer prices from departing much from costs. If rates are "high," then the Commission acts as if to protect and enhance the market power of the pipelines and electric power companies.

The examination of actual rates might well begin with that allowed in the Florida case. The Florida Gas Company in 1960 was allowed an overall return on capital of 6.0 percent and a return on equity of 12.5 percent, with equity accounting for only 15 percent of capital structure. Adjustments in the overall allowed return were made in 1962 (to 6.5 percent), in 1965 (to 7.0 percent), and in 1968-69 (to the aforementioned

7.25 percent). At the same time, adjustments were also made in the allowed return on equity, but increases in the equity-capital ratio in part eliminated these increases in rate of return; the rate stayed close to 12.5 percent until 1963, and thereafter fell to approximately 10 and then 9 percent as the equity ratio increased to 35 percent. The case at hand reversed this decline by allowing 9.9 percent in 1968 and 1969, with an equity ratio of 28 percent.

Were these limits what might be termed "generous," in the sense of allowing this firm to make more than the competitive level of profits? The Florida Gas Company in fact had more opportunity for profit making than it needed: in the first seven years of operation, it only earned from one-half to two-thirds of its allowed return on equity. This could have been a result of having to pay more for debt capital than originally forecast in 1960 so that, given the 6.0-percent to 7.0-percent limit on overall earnings, interest payments replaced equity returns. But such an explanation is not complete, because Florida failed to earn the overall allowed rate of return in each of these seven years (as shown in Table 4). Competition from other fuel sources, and relatively small industrial markets for energy in Florida, limited Florida Gas from earning what the Commissioners had allowed; in that sense, the Commissioners set no limits on the profits of this regulated firm.

Table 4

RATES OF RETURN FOR FLORIDA GAS TRANSMISSION COMPANY, 1960-66

	Rates of Return			
Year	Overall Allowed	Overall Earned	Equity Allowed	Equity Earned
1960	6.0	4.3	12.5	-8.3
1961	6.0	5.9	12.5	5.9
1962	6.5	6.4	14.7	8.5
1963	6.5	6.2	9.8	5.5
1964	6.5	5.4	9.2	5.9
1965	6.6	6.1	9.3	6.8
1966	7.0	6.4	9.4	8.3

Source: 42 F.P.C. 74, The Examiner's Decision at 95-120.

The Florida Company probably still made more-than-competitive profits. The measure of "high" profits is the cost of capital -- returns over the cost of capital are more than necessary to bring forth service. The "costs of capital" are elusive, but not so much so that the order of magnitude cannot be indicated.

The costs of capital for the investor are what he has to "give up" by buying the shares of the individual gas pipeline company, which is most likely the cash dividend and capital

gain on the shares of companies with the same riskiness of enterprise. These returns accrue at the rate $\rho_i = D_t/P_t + \Delta P_t/P_t$ where D_t is dividends per unit time t, P_t is share price and ΔP_t is the unit time change in share price. The dividends, when looked at on a per-share basis, come from earnings Y_t or from the sale of more shares S_t, and cannot exceed the amounts of revenues from these two sources minus net investment I_t: $D_t = \frac{1}{S_t}(Y_t - I_t) + \frac{\Delta S_t P_t}{S_t}$. The two relations, together with an explicit definition of the growth path of new investment, can be used to find that rate ρ_i which has been realized on alternative investments in the same risk class.

Three studies have been completed of these opportunity costs for the gas pipeline investor. Malkiel, Litzenberger and Rao, and McDonald* have all solved $\rho_i = f(P_t, D_t, I_t)$ for realized values of ρ_i from regression line relations with prices, dividends, and the growth inprofitability of new investment, The samples of "alternative investments" have all been drawn from the retail gas and electricity industries, on the assumptions that "utility companies comprise an equivalent risk class" (McDonald, p.). This is the proposition often stated before the Commission, and implicit in the Commissioners' use of indicators of comparable earnings: the opportunity cost of investment in gas transmission is the rate of return on electricity shares, since these are

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* All three studies are from the Bell Journal of Economics and Management Science as follows: B.G. Malkiel, "The Valuation of Public Utility Equities", Vol. 1, No. 1 (spring 1970); R. H. Litzenberger and C. Rao, "Estimates of the Marginal Rate of Time Preference and Average Risk Aversion of Investors in Electric Utility Shares: 1960-1966", Vol. 2, No. 1 (spring 1971); J. G. McDonald, "Required Return on Public Utility Equities", Vol 2, No.2., (autumn 1971).

freely available alternative investments and the conditions of market structure, demand, and costs are similar enough to make risk comparable.[10] The levels of costs of capital, and thus the implied "competitive" ceiling on the rate of return, are shown in Column 1 of Table 5. These apply to the pipeline for 1960-66, and are estimated marginal rates of return on alternative investment on the basis of estimates by Litzenberger and Rao for companies with the same debt rate and variance in earnings as Florida Gas Transmission Company. The actual Florida

Table 5

FLORIDA GAS TRANSMISSION RATES OF RETURN AND THE COSTS OF CAPITAL, 1960-66

Year	Costs of Capital	Earned Return on Equity
1960	6.7	-8.3
1961	5.7	5.9
1962	6.0	8.5
1963	5.5	5.5
1964	5.4	5.9
1965	5.1	6.8
1966	6.0	8.3

Source: Column 1 from Litzenberger and Rao (op.cit.) for Florida Gas Transmission's values of L,S_j; Column 2 as in Table 4.

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[10] Risk is measured relative to that of the market as a whole, since the investor can hedge any other variability in earnings.

Gas earnings rates are shown in Column 2. The measures show costs 1.5 points less than the earnings rates after the first year of operation.

Perhaps the Florida decision was exceptional, and not indicative of the Commissioners' intention. There were a number of earlier decisions on rates of return in the 1960's, many in proceedings in which municipalities and industrial gas purchasers made extensive presentations of rebuttal material on required rates of return. The Commissioners allowed "high" returns in almost all instances.

The actual allowed levels of rates of return are shown in Table 6, for all of the formal proceedings finished in the 1960's. The Commission's procedure was clear, regardless of the "reasons" recorded for particular high or low values in particular cases. The overall rate of return was limited to between 6.0 and 6.5 percent in 1961, with only one finding at 6.5 percent; this line was held to 1965, but with increased strain -- only one of the 1962 findings was not at 6.5 percent, and the 1964 and 1965 findings were at 6.5 percent. The break in 1968 took the level to between 6.5 and 7.0 percent; another break in 1970 generally held between 7.5 and 8.5 percent. Whatever the (market required) payment of interest on bonds in all these cases, the rate allowed on equity was that that permitted by an "average" or "overall" rate of return below the 6.0 to 7.0 percent ceiling, at least until 1970.

Table 6: DECISIONS ON GAS PIPELINE RATES OF RETURN, 1961-1970

Defendent Pipeline Company	Allowed Rates of Return, percent		Actual Rates of Return percent			Estimated Costs of Capital	
	equity (3a)	overall (3b)	equity (4a)	overall (4b)	av. for no. years (4c)	equity (5a)	Aa bond yield (5b)
(2)							
United Gas Pipeline	10.3	6.3	na	na	na	4.8	4.5
East Tennessee	12.0	6.0	na	na	na	4.8	4.5
Northern Natural	10.5	6.3	10.7	6.0	3	4.8	4.5
Kansas-Nebraska	10.8	6.5	13.0	6.0	3	4.8	4.5
Panhandle Eastern	10.5	6.3	16.6	7.1	2	4.8	4.5
Alabama Tennessee	9.3	6.5	27.4	10.6	2	5.2	4.4
Michigan Wisconsin	9.9	6.5	12.9	5.8	1	5.2	4.4
El Paso	12.0	6.2	10.2	7.1	2	5.2	4.4
Midwestern Gas	9.3	6.5	11.7	6.7	3	4.8	4.4
East Tennessee	8.5	6.5	13.4	7.8	3	5.3	4.5
Natural Gas Pipeline	9.5	6.9	12.6	6.4	3	7.3	6.4
Panhandle Eastern	11.2	6.6	15.2	7.4	3	7.3	6.4
Cities Service	11.2	6.6	na	na	na	7.3	6.4
Algonquin	10.4	7.5	na	na	na	9.0*	7.0*
Pacific Gas Trans.	11.6	7.3	na	na	na	9.0*	7.0*
El Paso	13.7	7.7	na	na	na	9.0*	7.0*
Southern Natural	11.0	8.5	15.6	8.8	1	9.0*	7.0*
Consolidated Gas Supply	9.4	7.8	na	na	na	9.0*	7.0*
United Gas Pipeline	11.4	7.9	na	na	na	9.0*	7.0*

figures.

Three conclusions can be drawn from these rates. First, they were not set by any particular reasoning process. The eight cases mentioning "comparable equity returns" included six that also considered "earnings-price ratios" of investments of comparable risk. The additional considerations made no difference, since the two groups averaged within 0.2 percent of each other. Two cases mentioned "rising debt costs" in later years and two stated the correct rate was a "matter of judgment", and these four all had "higher" allowed rates. But these "higher" rates were shared with five cases in which mention was most prominently made of the past successful history of the company. The arguments cannot be used to classify the results in terms of rate of return.

Second, the allowed rates did not limit the actual earnings for the company. The actual rates exceeded the allowed overall rates by more than 0.5 percent in the eleven cases for which one to three years actual experience were available. The actual equity rates exceeded allowed equity rates by 5.0 percent in the same eleven cases (as in Table 6).

Third, both the actual and the allowed rates exceeded the estimated costs of capital for investors in that period. In the early 1960's, estimates of the overall costs of capital were in the range of four to five percent (from McDonald, op. cit.), given that the marginal costs of equity capital were 4.8 percent and the more risky debt investments were offering at most 4.5 percent (as in Table 6). As a consequence, the realized and allowed equity

returns were both more than twice the cost levels, and the overall returns were more than one-fifth greater than costs of capital. Later in the decade, costs rose to within the 7.0 to 9.0 percent range -- still one to three points below the allowed limits on equity, but within one point of the allowed overall return.

What was the Federal Power Commission attempting to accomplish, in these cases? The results indicate that, most important, a level of rates was to be set that would hold for long periods with a minimum of case controversy. This by nature in an economy with a strong trend of interest rate inflation has to be a rate substantially in excess of the costs of capital. This is because cases are brought by pipelines when costs approach prices and they become "stacked", the more closely average costs approach the average price. Thus, to avoid stacked cases, the earliest cases should declare rates of return far above the costs of raising long term capital.

The Commission clearly does not try to do too much. They do not serve as the source of initiative for consumer-oriented reductions of prices to cost levels, because this would require low rate-of-return ceilings in the early years of the inflationary period and thus subsequent very frequent ceiling increases. They do not control the overall profitability of the pipeline companies. Either the lines "do better" on non-jurisdictional sales, or they are able to reduce costs systematically below expected levels for the periods between rate reviews, because actual returns exceed pre-set returns.

The general impression from the rate of return cases is that there were no pervasive or systematic regulatory restraints on profit-making by the pipelines. The Commissioners' intentions may have been to limit extreme profit-taking. But rates of return generally seem to have greatly exceeded costs, when the pursuit of maximum consumers' gains would have required the Commissioners to have rates equal to or less than costs.[11] The Commissioners would seem to have wanted more to reduce case load, adding to pipeline profit gains rather than to consumers' gains.

The rate of return controls on electricity producers.

The F.P.C. decisions on electricity company rates of return show no pattern whatsoever. Very few cases during the 1960's dealt with the rate of return on sales under F.P.C. jurisdiction -- those sales at the wholesale level of the industry, and in interstate commerce. Finding the "legal" rate was almost completely arbitrary, since joint capital costs had to be allocated between jurisdictional and non-jurisdictional sales and there were no general principles for doing so accurately. In the extreme, the F.P.C. regulated, by finding the "correct" rate of return, single sales involving 10 percent or less of total

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[11] That is, rates equal to average costs for all gas services, but equal to marginal costs for marginal service. If there are economies of scale, the rates on the marginal service are below average costs.

power production while state regulatory commissions set the rate of return on the rest of production; thus the Commission in some cases had to be in the business of setting a single price by rate of return regulation.

Even so, the Commission could have developed arbitrary but consistent rules. To the contrary, their procedure has been to treat each case differently. In Public Service Company of Oklahoma 25 F.P.C. 656 (1961), the F.P.C. reviewed the terms of exchange between Public Service and the Grand River Dam Authority and found them reasonable on the basis of both "cost analyses" and "sharing of the fruits" of production. But in a case involving the Brazos River Authority, 44 P.U.R. 129 (1962), the Commission took the position that the terms of exchange "must be tested by normal standards of rate making" or by the cost of service procedures only. In the Wisconsin-Michigan Power Company case (31 F.P.C. 1445 (1964)), an elaborate procedure of "classification and allocation" of costs was developed that, when applied, set certain differences between prices on sales to municipal and cooperative buying companies that allowed the same rates of return on the two classes. These allocation rules were then abandoned in the next case (in re Southwestern Public Service Company 57 P.U.R. 394 (1965)) where less than the allowed rates were permitted on sales to cooperatives because "sales to cooperatives have benefitted all of Southwestern's customers notwithstanding lower rates.... if the cooperatives' rates were raised, they would build their

own generating facilities." This appeal for lower rates because of "a superior bargaining position" was made again in St. Michael's versus Eastern Shore Public Service Commission 63 P.U.R. 3d 337 (1966). These cases, when viewed as a whole, cannot be considered to be any basis whatsoever for setting consistent and systematic limits on profits. There would seem to be no "case law" on electricity rates of return or on electricity prices.

The Effects of Regulation on Gas Pipeline Prices

The results of the "landmark" rate cases, in terms of the level of the overall and equity rates of return allowed by the F.P.C., would seem to be unimportant. The limits would not seem to have been "binding" on the companies, at least not until the last year of the (normal) five years or more between cases. As a consequence, prices would not seem much reduced, or consumers much protected "against undue or extortionate increases." This would seem to be a consequence; the evidence, however, has to come from an analysis of regulated prices as compared to unregulated prices.

The interstate natural gas pipelines have been in the business of purchasing natural gas in Texas, Louisiana, and other southwest states for sale to industry and municipalities along transmission routes leading to the large population centers in the Northeast and West. The terms of purchase and resale have been numerous and complex -- involving delivery

in the future of gas reserves as above-ground production and involving national or state regulation of the sellers and buyers at each level of the industry -- but the business has been conducted generally according to the public utility pattern. The pipelines have been assumed to be "natural monopolies," or at least treated as such by the invocation of certification procedures to prevent overlapping facilities. Profit constraint has been involved so as to produce the peculiar American blend of competitive performance from private companies operating in monopoly markets.

There are reasons for questioning whether the assumptions for policy, as well as the assumed results of profit regulation policy, hold. The pipelines may very well not be "natural monopolies," in the present time frame of reference for pricing, because the operating costs and capacity-expanding costs of established pipelines appear to be directly proportional to gas throughput. That is, two or three lines may each have the same unit costs of transport as would only one pipeline.[12] The state of affairs could be such that, not only are the pipelines not "natural monopolies," but they are not "monopolies." Historical patterns of construction of new pipelines in the 1960's duplicated earlier lines moving gas to

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[12] Cf. S. H. Wellisz, "Regulation of Natural Gas Pipeline Companies: An Economic Analysis", LXXI Journal of Political Economy 33 (February, 1963).

growing centers of population, so that there were two, three and sometimes more companies offering gas to large industrial or retail utility buyers in the Northeast and Midwest.

The reasons for "poor results" from regulation have been discussed in the previous section. The possibilities can be confirmed or denied by comparing prices under regulation with those on unregulated industrial sales. The next few paragraphs outline the logical basis for such a comparison. This necessarily involves description and synthesis of economic models of the effects of regulation, in particular those termed "A-J-W models" which were in part derived from *a priori* analysis of regulated pipeline behavior.[13] The description is for the purpose of finding testable propositions about regulated as compared to unregulated prices. The subsequent paragraphs describe the data to be used for testing regulated against unregulated prices, and the final paragraphs in the section report regression equations and a concluding evaluation on the effects of F.P.C. regulation of pipelines. While tentative, the conclusion is that the effects are *very slight*, but in the expected direction. While they follow closely the A-J-W theory on regulatory effects, the extent from regulatory constraint is negligible in the midst of much more important cost, demand, and institutional factors

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[13] After H. Averch and L. Johnson, "Behavior of the Firm Under Regulatory Constraint", *American Economic Review* 52, (December 1962), pp. 1052-69, and S. Wellisz, *op. cit*.

in pricing.

Hypotheses on regulated versus unregulated prices. The pipeline enterprise faces demands for gas by retail public utility companies seeking to deliver to home consumers a total amount q_1 in a year's service commitment, and demands for direct consumption q_2 by industrial consumers during the same period. Both are contract demands with expressed or implied volumes (implied by commitment of capacity) and major considerations are price $P_1 = f(q_1)$ and $P_2 = f(q_2)$.

Monopoly control of prices on the sales to home consumers could be present even where there are two or three pipelines, if there is extensive interfirm cooperation. Although there are the same number of suppliers of gas for industrial buyers, control of industrial prices conceivably could be more limited still, because of extensive interfuel substitution. Also, cooperation could be much more limited by the lack of regulatory mechanisms for reporting and delaying price changes (including "discounts" by a transporter seeking to take sales away from another transporter).

The pipeline enterprise incurs total costs $C = f(q_1,q_2,K)$ for operating existing capacity to provide q_1 and q_2, and for adding to capacity K. These costs are related almost entirely to distance and volume, so that marginal costs $\partial C/\partial q_1$, $\partial C/\partial q_2$ are for carrying the same volume farther, or a larger volume the same distance.

There are three types of constraints on the pipeline's control of prices, the first being capacity constraints, the second those implied by the extent of market competition, and the third in F.P.C. regulation of profits.

Prices without regulation, whether on sales to industry or to retail utilities, would be determined by the nature and extent of interfirm rivalry. The possible forms this rivalry could take are more than numerous. At one extreme, perfect cooperation among pipeline sellers could be the rule, so that prices were "monopolistic". Prices would be highly discriminatory in such a case, because differences in demand conditions and the absence of "leakage" of sales by resale from the low priced buyer to the high priced buyer would make discrimination extremely profitable. The pipeline company might even have the opportunity to charge different "marginal prices" for each unit-volume sold to the same consumer, given that resale could be prevented even on the last units purchased by low priced users. The perfectly discriminatory "marginal prices" could be quoted by the expedient of setting different initial charges for the establishment of different levels of service which, when added to the marginal charge per unit of delivered gas P_1 and P_2, results in profits

$$R = \int P_1 dq_1 + \int P_2 dq_2 - C(q_1, q_2, K) \quad \text{subject to } q_1 + q_2 \leq K.$$

The company sets outputs and prices according to the first order

conditions[14] for the maximization of revenues

$$G = \int P_1 dq_1 + \int P_2 dq_2 - C(q_1,q_2,K) - \gamma(q_1+q_2- K)$$

so that relative prices are $P_1 = P_2 + (\partial C/\partial q_1 - \partial C/\partial q_2)$ and quantities are $q_1 + q_2 = K$.

Competitive constraints on pricing would follow from not having achieved this degree of cooperation. The effects of rivalry could take many forms, but among the most likely would be the disappearance of perfect discrimination, as the high priced buyer from one pipeline sought -- with success -- to become a lower priced buyer from another pipeline. The two-part tariffs could not be put into effect so that all buyers would pay the same prices per unit-volume, for different volumes. Thus, the pipeline would operate as if limited to revenues

$G = P_1q_1 + P_2q_2 - C(q_1,q_2,K) - \gamma(q_1+q_2- K)$, so that maximum-profit prices on two classes of service would be such that

$P_1(1+ 1/e_1) - \partial C/\partial q_1 - \gamma = 0$ and $P_2(1+ 1/e_2) - \partial C/\partial q_2 - \gamma = 0$

where $e_i = -(P_i/q_i)\partial q_i/\partial P_i$, the price elasticity of demand.

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[14] This follows closely on W.J. Baumol and A. Klevorick "Input Choices and Rate of Return Regulation: An Overview of the Discussion" and I. Pressman "A Mathematical Formulation of the Peak-Load Pricing Problem", both from the Bell Journal of Economics and Management Science, Vol. 1, No. 2, pages 162-190 and 304-327 respectively (1970). Here the discussion is centered on pricing, rather than input factor ratios, for testing purposes, so that propositions appear to be different while they are not.

Thus the relative prices would be

$$P_1 = \frac{(1+ 1/e_2)}{(1+ 1/e_1)} P_2 + \frac{1}{(1+ 1/e_1)} (\partial C/\partial q_1 - \partial C/\partial q_2)$$ where the

total quantities would be $q_1' + q_2' = K'$

Prices when only residential sales are regulated. The effects of regulation on pricing of course depend on the nature of the controls applied by the regulatory commission. There are many ways of controlling the firm, including setting price directly, but the F.P.C. generally follows policies of setting dollar limits on profits through the artifice of finding fair rates of return on investment. We will avoid the artifice here and assume directly that the Commission holds profits on regulated sales q_1 to M, so that $P_1q_1 - \alpha C = M$, where α is the proportion of total costs attributed by the F.P.C. to regulated sales.

The profits on industrial sales would not be so constrained, so that with revenues subject to the λ regulatory constraint designated $G = P_1q_1 + P_2q_2 - C(q_1,q_2,K) - \gamma(q_1+q_2-K) + \lambda[P_1q_1 - \alpha C(q_1,q_2,K) - M]$, the first order conditions for maximum profits specify the two prices as $(1+\lambda)[P_1(1+ 1/e_1)] - (1+\alpha\lambda)\partial C/\partial q_1 - \gamma = 0$ and on the other class $P_2(1+ 1/e_2) - (1+\alpha\lambda)\partial C/\partial q_2 - \gamma = 0$; thus, under these conditions, the relative prices are

$$P_1 = \frac{1}{(1+\lambda)} \frac{(1+ 1/e_2)}{(1+ 1/e_1)} P_2 + \frac{(1+\alpha\lambda)}{(1+\lambda)} \frac{1}{(1+ 1/e_1)} \left\{ \frac{\partial C}{\partial q_1} - \frac{\partial C}{\partial q_2} \right\}.$$

This equation for relative prices under regulation can be compared with the first equation, for the same market and production conditions but without regulation. They differ by the factor $1/(1+\lambda)$ in the coefficient of P_2, and the factor $(1+\alpha\lambda)/(1+\lambda)$ in the coefficient of the cost difference $(\partial C/\partial q_1 - \partial C/\partial q_2)$. Both are dependent on λ, the "regulatory constraint" factor, and the interpretation of this factor is central to the assessment of effects from regulation. One interpretation is based on differentiating the revenue function G with respect to the constraint M, for $\partial G/\partial M = -\lambda$, so that the factor is the increase in total profits resulting from a unit increase in those profits allowed on regulated sales. That is, if $\lambda < 0$ (a condition that clearly will hold) and $\lambda > -1$ then profits as a whole increase as the constraint on M is relaxed but not by as much as the allowed increase in M. Alternatively, $\lambda < -1$ (when demand is everywhere inelastic) and an increase in allowed profits allows both cost reductions and revenue increases, so that overall profits increase by more than the allowed amount of increase on only the regulated sales. The first alternative set of regulatory conditions ($\lambda > -1$) results in prices on regulated sales that are relatively higher than on unregulated sales; the value of $1/(1+\lambda) > 1$ so that regulated prices are raised relative to unregulated prices.

The higher regulated price, relative to the direct-sale unregulated price, is not counter-intuitive. In the short run, with full use of capacity, the new application of regulatory rules would require profit reductions on regulated sales that could take place only by reducing regulated output and consequently increasing regulated price. In the long run, the profit constraint applied to retail utility purchases would increase the profitability of capital relative to other inputs and thus the level of total investment. If there were economies of scale, increased capacity would reduce marginal costs and thus the absolute level of prices on both regulated and unregulated sales. The increased capacity would be more fully devoted to the unregulated sales because marginal output in the unregulated sector would now be relatively more profitable. This follows from attributed costs on unregulated sales being lower [as shown by the $(1+\alpha\lambda)$ term on unregulated costs] and from relative profit reduction on regulated sales (as shown by M). Marginal output in the regulated sector should reduce profits, in other words, so that there should be a long run relative decline in regulated sales and a relative increase in regulated prices.

The second alternative is that $\lambda < -1$, circumstances under regulation in which prices have been so reduced that total revenue is reduced by further price reductions. Then the relative price under regulation P_1 is lower than P_2 as a result of

regulation (that is, $1/(1+\lambda) < 1$). Price has been pushed down so far that any relaxation in M would imply that output could be reduced, regulated price increased and the unregulated price reduced. These circumstances, which may be termed "severe regulatory constraint" are conceivable if not likely given the way that the F.P.C. goes about setting the limits on rate of return.

Rate of return regulation. Merely setting limits on total profits, given an arbitrary α, can be compared with regulation by the full procedure of setting a maximum rate of return on capital. This rate of return procedure has the effect of enhancing the relative differences between unregulated and regulated prices shown above, at least when the procedure results in returns greater than the economic costs of capital. Consider the profit function $R = P_1q_1 + P_2q_2 - r_1x_1 - r_2x_2$, where x_1 are capital resources and x_2 non-capital resources available to the regulated firm at prices r_1, r_2 respectively.[15] The restraint on profits is that $P_1q_1 - \alpha s_1x_1 - \alpha r_2x_2 = M$, where s_1 is the allowed rate of return on capital such that $s_1 - r_1 = V \geq 0$. The first order conditions for

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[15] This follows directly from Baumol and Klevorick, op. cit.

$$G = P_1 q_1 - P_2 q_2 - r_1 x_1 - r_2 x_2 - \gamma(q_1 + q_2 - x_1) + \lambda(P_1 q_1 - \alpha s_1 x_1 - \alpha r_2 x_2 - M)$$

include

$$(1+\lambda)P_1(1+ 1/e_1) - (1+\alpha\lambda)(r_1 \partial K/\partial q_1 + r_2 \partial L/\partial q_1) - (1+\alpha\lambda)(s-r_1)\partial K/\partial q_1 = 0$$

and $P_2(1+ 1/e_2) - (1+\alpha\lambda)(r_1 \partial K/\partial q_2 + r_2 \partial L/\partial q_2) - (1+\alpha\lambda)(s-r_1)\partial K/\partial q_2 = 0.$

If marginal costs $\partial C/\partial q_1$ are defined as $(r_1 \partial K/\partial q_1 + r_2 \partial L/\partial q_2)$, then

$$P_1 = \frac{1}{(1+\lambda)} \frac{(1+ 1/e_2)}{(1+ 1/e_1)} P_2 + \frac{(1+\alpha\lambda)}{(1+\lambda)} \frac{1}{(1+ 1/e_1)} \left\{ \frac{\partial C}{\partial q_1} - \frac{\partial C}{\partial q_2} \right\} +$$

$$\frac{(1+\alpha\lambda)}{(1+\lambda)} \cdot \frac{1}{(1+ 1/e_1)} \cdot (s-r_1) \cdot \left\{ \frac{\partial K}{\partial q_1} - \frac{\partial K}{\partial q_2} \right\},$$

the same expression for relative prices as in the previous analysis for maximum dollar profits, but with the addition of the last term on the right hand side of the equation. This last term is greater than zero if the marginal cost difference is greater than zero -- if the distance from purchase of the gas to final delivery is greater for regulated sales than for unregulated sales -- so that the relative price difference is enhanced when rate of return limits are set only on the regulated sales. It is as if there were a premium on costs for the excess allowed return; thus whatever the effects on relative regulated prices from the severity of the regulatory constraint, these effects are always greater under this regimen.

Query: what are the effects of uncertainty? So far, we have assessed the equilibrium conditions for relative prices, assuming that demands and costs are known and that regulation is continuous as well as certain. These assumptions do not hold in all markets for gas, and actual conditions may depart so extensively from those assumed that the question could be raised on the usefulness of an analytical apparatus based on them.

The answer to the question depends on the extent to which models with uncertainty and with dynamic regulatory conditions differ from the certainty-static models. These more complex models remain to be developed so that no straightforward comparison can be made. But at this point, of the many promising but only partially developed uncertainty analyses, those based on market and regulatory conditions prevailing at the present time differ little from the certainty-static models. The reasons for this state of affairs are two. First, with respect to uncertainty, cost and demand conditions different from those expected must occur at all levels of prices and volumes of service, but it seems plausible to assume that variation from expected cost and price levels is going to be greater when gas demand is highly elastic with respect to prices of other sources of energy. These demand conditions occur most frequently in unregulated markets -- almost as a matter of

classifying these markets as competitive enough not to be regulated. That is, uncertainty has the greatest effects in unregulated markets, and these effects show up in the elasticities of demand expected by the suppliers. Second, with respect to regulation, the Commission operates with an extended lag, as the analysis of F.P.C. staff surveillance in Chapter 1 shows, and as the case rate-of-return decisions also show. These "imperfections" of regulation take the form of departures from severe constraint, and should appear in the guise of particular values of λ.

These two assertions can be summarized. First, uncertainty in demand should have a greater effect on pricing in unregulated markets. The effect should, however, appear in expressed or implied values of the various measured conditions of demand, and not in the estimates values of the λ constraint. The relative regulated prices would not be different than expected from the certainty analysis. Second, regulation under uncertainty roughly conforms to the model's assertions, but with the effects of uncertainty working through in the same way as if Commission controls had been reduced or relaxed.

Pricing summary, At this point, the rather extended array of price variations might well be summarized. The price hypotheses differ quite markedly from each other, when there are differences in degrees of market control and in the nature

of regulation. When it is possible for pipelines to charge a different price to each retail distributor or industrial buyer, and there is no regulation, elasticities of demand do not enter the coefficients a,b of the equation for relative residential price $P_1 = aP_2 + b(\partial C/\partial q_1 - \partial C/\partial q_2)$; rather, a=1, b=1 where P_2 is the price on a comparable industrial sale and $\partial C/\partial q_1$, $\partial C/\partial q_2$ are residential and industrial transport costs. When, for reasons of rivalry between pipelines in the same market, prices turn out to be uniform to all industrial or all retail utility buyers -- to all buyers of q_2, or all buyers of q_1 -- the relative elasticities of demand enter both coefficients a and b, so that

$$P_1 = \frac{(1+ 1/e_2)}{(1+ 1/e_1)} P_2 + \frac{1}{(1+ 1/e_1)} \left\{\frac{\partial C}{\partial q_1} - \frac{\partial C}{\partial q_2}\right\}.$$

There is further contrast created by the effects of regulation, as well. Regulation results in testable differences in coefficients -- terms including the regulatory constraint λ are found in both a and b; these λ terms change the size of the coefficients, so that the regulated price is increased relative to the unregulated price if regulation is weak, and so that regulated price is reduced relative to the unregulated price under the most severe restraints on profits and service.

Data for Testing Regulated Against Unregulated Prices

The information on prices charged by the interstate pipelines is voluminous, complicated and not altogether useful for testing the effects of regulation. The regulatory process itself may be responsible, since the F.P.C. demands annual information on assets and liabilities in order to control rates of return, rather than demanding detailed statements on flows of income by the individual gas contract in order to control prices. Quantity information is better. The Commission demands rather complete information on the volume of regulated sales, but only partial information on the size of unregulated sales (for cost allocation purposes alone). In all, there are limited data on contracts with the regulated retail gas distributing companies in the *Form 2 Annual Reports* to the F.P.C. that indicate the "demand charges" (annual or monthly charges for providing service, where these charges are set according to the rate of delivery of each buyer at the *peak* period) and the "commodity charges" (the prices per mcf of gas delivered) on each retail gas sale. There are annual statistics in the *Form 2 Reports* on the volume and total revenues from unregulated direct industrial sales; these have been supplemented by interviews and special surveys of particular pipelines, to find the unit prices charged on the rates of delivery for unregulated sales in 1969.

The price information is to be used to test the coefficients a,b in $P_1 = aP_2 + b(\partial C/\partial q_1 - \partial C/\partial q_2)$ for the effects of pipeline and inter-fuel competition, and for the effects of regulation. Since this expression has been derived with respect to marginal prices, the commodity charge on regulated sales is designated to serve as P_1 and the unit price on unregulated sales is designated P_2.[16] The tests call for computation of a and b by least squares regression, so that data are required on the marginal costs of transport $\partial C/\partial q_1$ and $\partial C/\partial q_2$ as well. After finding a and b, there are tests for coefficients to find the size of λ, so as to infer the severity of regulation. The tests require independent estimates of e_1 and e_2 so as to be able to separate the λ and e_i effects found in both a and b. These requirements will be discussed in turn.

The marginal costs of transport. These costs can take on many different values, and finding the proper value depends

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[16] In a few cases on which data were incomplete, there may be a demand charge and a commodity charge on q_2. With $P_2^* = P_2 + w/q_2$ as the unit price, where w is the "demand" additive to the marginal or commodity charge, the equation is still the same -- that is, $P_1 = aP_2^* + b(\partial C/\partial q_1 - \partial C/\partial q_2) + d$ with a,b as given above -- but with the possible addition of a constant term d. This equation can be derived by substituting $P_2^* = P_2 + w/q_2$ in the appropriate objective functions in the preceding section of this chapter. If $\partial w/\partial q_2 \neq 0$, or charges in fact do vary with the amount of gas delivered, then an additional term appears. This additional term is a constant denoted "d".

on choosing the relevant time period, on accounting for the location of the pipeline, and for differences in factor prices of capital and fuel. For purposes of examining the results of recent price regulation, the time period of a single year in the interval 1952 - 1967 has been chosen and costs have been designated as "expenditures on operations, maintenance, administration, transmission, storage and depreciation" in each of these years for each of eight large interstate pipeline companies.[17] These companies have been chosen because they have similar location terrain and similar technology in their main pipelines; each has more than 1,000 miles of total pipeline, 75 percent of which had diameter equal to or greater than 15 inches, and the main lines were constructed fairly close to each other over the same types of terrain between the southeast and northeast in the 1950's.[18] The length of the main line of each transporter was estimated by inspection of maps and engineering drawings, to provide data for the variable "m = mileage",

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[17] The Federal Power Commission Statistics for Interstate Natural Gas Pipeline Companies 1952-1967, annual volumes.

[18] The pipelines were: The Atlantic Seaboard Corporation, Colorado Interstate Natural Gas Pipeline, Michigan-Wisconsin Pipeline Company, The Natural Gas Pipeline Company of America, Tennessee Gas Transmission Company (a division of Tenneco), Texas Eastern Transmission Company, Transcontinental Gas Pipeline Corporation, and Trunkline Gas Corporation. The exception to the rule on location similarity is the Colorado Interstate Company.

and throughput of gas was recorded as "q = volume."[19]

The most general equation form chosen was $C = \alpha + \beta\, m \cdot q$ which, when fitted to the sample, proved to be $C = 44.7(10^3) + .57 m \cdot q$, $R^2 = .958$ with α and β in cents per thousand cubic feet of gas transported for 100 miles. Attempts were made to account for differences in factor prices among the transporters, and for the "mix" of combinations of volume and mileage as well, but they did not improve the fit as measured by R^2. The introduction of variables to account for the year of the observation and/or to account for the particular pipeline in that observation did not change the values of α or β nor increase the value of R^2. The measure of marginal costs is .57 cents per hundred miles, so that values of transport cost differences ($\partial C/\partial q_1 - \partial C/\partial q_2$) are taken to be $.57(m_1 - m_2)$ where m_1 and m_2 are 100 main-line miles of distance from a common gas field origin point to the points of resale of regulated gas q_1 and unregulated gas q_2.

The elasticities of market demand. The price-sensitivity of gas demands of home and industrial consumers has been estimated in a number of recent studies, but mostly for the purpose of analyzing the effects of regulation of the field producer prices.[20] There have been no studies of the specific elasticities

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[19] Volume is recorded as annual sales in F.P.C. Statistics, op. cit.

[20] Cf. J.D. Khazzoom "The F.P.C. Staff's Econometric Model of Gas Supply" Bell Journal of Economics and Management Science, Vol. 2, No. 1 (Spring 1971) and P. MacAvoy "The Regulated-Induced Shortage of Natural Gas" Journal of Law and Economics (Spring 1971).

of demand of those buying gas from the interstate pipelines. In order to make first estimates of e_1, e_2 here, a sample of contract prices and quantities has been constructed and a regression analysis of the sample completed with equation forms suggested by the more detailed studies.[21]

The markets for gas in which the pipelines are sources of supply probably encompass whole metropolitan regions in most cases. The purchasing retail distributors can go to alternative sources of gas that deliver within their metropolitan regions, whether pipeline company or LNG company; the industrial consumer can go to the same sources, as well as suppliers able to provide large volumes of coal and fuel oil, in the same locations or with access to transportation to these locations. The markets for retail distributor sales are the metropolitan regions in which they take place; for direct industrial sales, the relevant regions over which transactions could take place are broader.

Data have been collected on transactions in a sample of these market regions. These are data on 1969 prices of all fuels, and on the contract volumes of delivered natural gas, for 17 metropolitan areas in which there were purchases by

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[21] See P. Balestra, The Demand for Natural Gas in the United States (North Holland, 1967) and H.S. Houthakker and L.D. Taylor, Consumer Demand in the United States 1929-1970 (Harvard University Press, 1966).

retail public utilities. The observations from these conform to "market transactions". But information on the 49 purchases by industrial buyers were limited to specific transactions, rather than on all those taking place in a market region. Therefore, observations on industrial sales are more limited than they should be to indicate industrial market behavior -- they do not cover all the volumes within a market region containing the specific sale, nor the prices of alternatives.

The demand function on retail sales could take a number of forms. For illustrative purposes, and in order to test for relative prices as hypothesized, the form chosen is:

$$\log(q) = \alpha + \beta\log(P_g) + \gamma\log(P_F) + \partial\log(Y) + \varepsilon\log(N) + \phi\log(TDD) + u$$

where q is annual gas receipts of retail utilities, P_g is the marginal gas price to these utilities, P_F the price of an alternative fuel, and Y, N, TDD the "market size" variables per-capita income, population, and temperature degree days.[22] The residential demand function, as found by fitting a least squares regression, proved to be:

$$\log(q) = 8.106 - \underset{(1.342)}{1.907}\log(P_g) + \underset{(0.816)}{0.390}\log(P_F) + \underset{(2.792)}{0.545}\log(Y)$$

$$+ \underset{(0.337)}{0.564}\log(N) - \underset{(0.711)}{0.445}\log(TDD); \quad R^2 = .374$$

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[22] In the absence of more than one year's data, lagged terms in q, P_g to account for adjustment processes had to be deleted.

a relationship noted for its general agreement with empirical regularities found elsewhere in energy demand studies -- gas price decreases have the effect of increasing quantity demanded, and income, population and other fuel price increases have the effect of increasing demand. But the regularities are not extremely marked; the coefficients are not statistically significant and the equation explains only 37 percent of the variation in the dependent variable. Although the price elasticity seems quite high -- the coefficient is -1.907, clearly in the elastic range -- it is not statistically significantly different from zero. The estimate also seems to be subject to wide variations; after collecting 1968 data on q_1 and N for these 17 locations, the regression was refitted for $q = f[q(t-1),P_g,N,....]$ with the result that the coefficient for $\log(P_g)$ equaled -0.950 and for $\log[q(t-1)]$ equaled +0.970; both were statistically significant, and $R^2 = .998$. Therefore, the conclusions from these regressions must be limited. All that can be offered is that the elasticity coefficient of residential distributor demand lies between zero and -1.9, with the most likely value between -1.0 and -1.9, so that demand is "elastic".

The 1969 data on industrial demand, including price and quantity information on 49 direct pipeline sales, has been used to fit further regression equations. Using corporate employees as a measure of "size of market", the industrial demand regression

was found to be:

$$\log(q_2) = 11.372 - \underset{)0.980)}{1.785} \log(P_g^*) - \underset{(0.114)}{0.249} \log(dP32) -$$

$$\underset{(0.125)}{0.144} \log(dP33) - \underset{(0.168)}{0.205} \log(dP29) + \underset{(0.192)}{0.681} \log(EES);$$

$$R^2 = 0.306$$

where dP32, dP33, and dP29 are dummy variables for price additives for three industries. Here the coefficients of P_g^* and EES are statistically significant, and the first of the dummy price additives (for classification 32, the stone-clay-glass industry) is also different from zero. The remaining coefficients do not differ from zero, and R^2 indicates that only 30 percent of the variance in q_2 is explained by the regression. Demand would appear to be more elastic than for retail distribution: the elasticity for the base industry (chemicals) is -1.785, for industry 32 (stone-clay-glass) is -1.785- .249 = -2.034, for industry 33 (primary metals) is -1.785 - .144 = -1.929, and for industry 29 (petroleum refining) the estimate is -1.785 - .205 = -1.990. Each of these seems to be close to -2.0, beyond the range from -1.0 to -1.9 found for the elasticity of retail distributors demand.

Further regression analysis suggests that industrial demand is even more elastic than these estimates indicate -- particularly where there are close gas substitutes. Data were available for a more limited sample of 39 gas industrial sales, including price and quantity (excluding sales to companies in the petroleum refining industry) and that also included industrial

coal prices roughly at those locations. The regression from this sample was:

$$\log(q_2) = 10.954 - \underset{(0.918)}{3.471} \log(P^*_{g2}) - \underset{(0.542)}{0.962} \log(dP32) -$$

$$\underset{(0.673)}{1.070} \log(dP33) + \underset{(1.346)}{1.578} \log(P_c); \quad R^2 = .378.$$

Here the estimated elasticities varied from -3.47 (on sales to firms in the chemicals industry) to -4.54 (on sales to companies in the primary metals industry). Gas demand would seem to be less elastic where the use of gas is as a process raw material with only fair substitutes (as in chemicals) and more elastic where the use is as a boiler fuel with very close substitutes (as in metals).[23]

Equations have also been fitted for two of the industries separately (given that there were sufficient data). These show substantial price elasticities, and also show differences between them sufficient to explain in part the low values of R^2 in the combined-industries equations. The equation for demand for gas in the chemicals industry is:

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[23] A more complete but not necessarily illuminating form is as follows:

$$\log(q_2/EES) = 0.757 - \underset{(1.175)}{2.168} \log(P^*_{g2}/P_F) - \underset{(0.542)}{1.109} \log(dP32)$$

$$- \underset{(0.689)}{1.049} \log(dP33) + \underset{(0.821)}{2.958} \log(P_c/P_F); \quad R^2 = .364$$

where P_c equals price of coal and P_F equals a fuel price index.

$$\log(q_2) = -2.021 - \underset{(2.118)}{3.486} \log(P^*_{g2}) + \underset{(0.315)}{0.839} \log(EES) +$$

$$\underset{(1.938)}{4.049} \log(P_c); \qquad R^2 = .567$$

for 12 observations, and demand in the stone-clay-glass industry is:

$$\log(q_2) = 11.641 - \underset{(1.371)}{2.778} \log(P^*_{g2}) + \underset{(0.239)}{0.819} \log(EES) +$$

$$\underset{(0.998)}{1.163} \log(P_c); \qquad R^2 = .232$$

for 19 observations. They indicate values of $e_1 = -3.49$ and -2.78 respectively, and as such add to the impression that industrial demand elasticity lies in the range from -2.0 to -3.5. This range, along with values of retail utility demand elasticity between -1.0 and -1.9, will be used in the calculations for the λ effects from regulation.

Demand conditions facing the individual pipeline. The conditions of market demand may not be the primary determinants of individual pipeline pricing decisions when there are a number of pipelines serving the same metropolitan region. The demand elasticities critical for setting prices charged by individual pipelines could differ from the market demand elasticities in many circumstances; for example, if the prices of one or a few firms were reduced below the current market level, the price cutters could receive a disproportionate market share of new contract sales; this larger share would not be indicated by

the estimated e_1 coefficients for the market as a whole.[24] Rather, the correct estimate of elasticity would be greater, indicating that there would be incentives for systematically lower prices on either residential or industrial deliveries than those consistent with estimates of market e_1, e_2.

How much lower prices should be under "rivalry" depends on the nature of the pipeline firms' interaction, and there are any number of theories as to that nature. The theory implying the greatest reduction -- short of an outbreak of perfect competition -- while still producing relations between relative firm size, the quality of information, and lower bounds on price, is the Cournot theory. Cournot in fact replaces e_1 by ne_1 for "n" equivalent-sized firms in all pricing conditions described above, where e_1 is equilibrium market elasticity for market-wide price determination (even though individual firm elasticity is larger at each stage of price setting).[25] A first measure of the extent of any such interaction, in terms of finding ne_1 or ne_2 in the relative price equations, can be made by observing the coefficients in price equations where no regulatory effect enters.

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[24] For this to be more than a transient phenomenon, the larger market share has to be realized for a long enough period to more than compensate for the price cut or price reduction: cf. D. Orr and P. MacAvoy, "Price Strategies for Cartel Stability", Economica, 1963.

[25] Cf. W. Vickrey, Microstatics (New York, 1964), pp. 337-38.

Consider the relative price equation $P_2^*(x) = aP_2^*(y) + b(\partial C/\partial q_{2x} - \partial C/\partial q_{2y})$ where $P_2^*(x)$ and $P_2^*(y)$ are both samples of industrial prices, one for buying industry X and the other for buying industry Y, and $\partial C/\partial q_{2x}$, $\partial C/\partial q_{2y}$ are the marginal costs of transporting to each of the points in the sample. According to the analysis in the last section $a = [1+ 1/e_y]/[1+ 1/e_x]$ and $b = 1/[1+ 1/e_x]$ since both sets of sales prices are unregulated; if there is systematic Cournot rivalry, then e_x, e_y should be replaced by ne_x and ne_y with the result that both coefficients are reduced in size.

This equation has been fitted by least squares to 40 observations of 1969 annual sales of four pipelines to companies in the petroleum industry and the primary metals industry. The prices are $P_2^*(29)$ for petroleum and $P_2^*(33)$ for primary metals, the marginal costs are $\partial C(29)/\partial q_2$ and $\partial C(33)/\partial q_2$ for transporting along any one of the four pipelines. The relationship fitted in the regression form is[26]

$$P_2^*(29) - P_2^*(33) = \Delta P_2 = (a-1)P_2^*(33) + b[\partial C(29)/\partial q_2 - \partial C(33)/\partial q_2] + d.$$

The first comparative equation for price is

$$\Delta P_2 = \underset{(0.048)}{-0.936}\, P_2^*(33) + \underset{(0.182)}{1.301}[\partial C(29)/\partial q_2 - \partial C(33)/\partial q_2] + 266.4 \qquad R^2 = .947$$

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[26] The constant term accounts roughly for pipeline-to-pipeline differences in transport costs. (These differences are ignored by taking $[\partial C/\partial q_i - \partial C/\partial q_j] = .57[m_1 - m_2]$ for all lines.)

with all prices in tenths of cents per Mcf of gas, and the implied elasticity of demand of buyers in petroleum from a single pipeline is b = 1/(1+ 1/ne) or ne = -4.32. The second comparative price equation is for 87 observations on $P_2^*(33)$, primary metals, against $P_2^*(49)$ electricity:

$$\Delta P_2 = \underset{(0.603)}{-0.572}\, P_2^*(49) + \underset{(0.572)}{2.581}[\partial C(33)/\partial q_2 - \partial C(49)/\partial q_2]$$

$$+198.857 \qquad\qquad R^2 = .245$$

and the elasticity of demand ne in primary metals equals -1.63. The third comparative price equation is based on 242 observations of contracts with stone-clay-glass manufacturers (32) and the electricity generating companies (49), and is:

$$\Delta P_2 = \underset{(0.064)}{-0.407}\, P_2^*(49) + \underset{(0.298)}{1.061}[\partial C(32)/\partial q_2 - \partial C(49)/\partial q_2]$$

$$+ 135.932 \qquad\qquad R^2 = .161$$

with the elasticity of demand of stone-clay-glass manufacturers ne = -17.66. The fourth comparative price equation, from 44 observations of $P_2^*(28)$ chemicals against $P_2^*(33)$ primary metals, is:

$$\Delta P_2 = \underset{(0.120)}{-0.927}\, P_2^*(33) + \underset{(0.426)}{1.504}[\partial C(28)/\partial q_2 - \partial C(33)/\partial q_2]$$

$$+ 349.928 \qquad\qquad R^2 = .635$$

and the implied single-seller elasticity of demand is -2.98. All four equations show estimates of ne that are similar to or greater than those for market demand e given above, so that it has to be concluded that n is equal to or greater than 1, or that the elasticity of demand for the purposes of individual pipeline price setting is the same or greater than the industry-wide demand elasticity; based on the difference in ne increase, n would seem to be between 1 and 2. There would seem to be some price-reducing

effect from the presence of a second (and perhaps third) pipeline on the supply side of most industrial gas purchase markets.

The price setting practices in retail utility gas markets seem quite different from those in industrial markets. The pipelines have long set two-part prices on contracts with retail utility companies, under the jurisdiction of the Federal Power Commission. The marginal price or "commodity charge" has not been set at a level in keeping with the residential market elasticities of demand, but as if marginal prices were being used to add to marginal consumption while the initial or demand charges determined the bulk of the returns from providing service. This can be seen from using a sample of 26 paired residential sales for 1969 to fit the regression[27] $\Delta P = b(\partial C/\partial q_{1a} - \partial C/\partial q_{1b})$ for sales at locations a and b. First, $\Delta P = +0.869(\partial C/\partial q_{1a} - \partial C/\partial q_{1b})$ and $R^2 = .312$, results that are in keeping with perfectly discriminatory pricing (where $b = 1$, as shown by the first of the theoretical propositions above on relative prices). That is, the pipelines have made selective reductions at the margin, to small utilities or to those larger companies having only marginal opportunities for resale. A second regression was fitted as follows: $\Delta AR = 2.451(\partial C/\partial q_1 - \partial C/\partial q_2)$; $R^2 = .317$ for AR equal to the average revenue from demand and commodity charges, and the elasticity ne implied by the fitted value

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[27] Here $P_1 - P_2 = \Delta P = (a-1)P_2 + b(\partial C/\partial q_1 - \partial C/\partial q_2) + d$, with $a=1$, $d=0$ because the samples q_1, q_2 both have the same price elasticity and are carried on the same (or almost identical) pipelines.

of b is -1.70. The ΔP regression indicates that commodity prices have been set in a discriminatory fashion, and the ΔAR regression indicates that the average of demand and commodity prices has been set close to the equivalent "best profit" single charge if market demand elasticity were close to -1.70. Since the value of -1.70 is within the range of elasticities observed for retail gas utility markets in 1969, it has to be concluded that the industrial elasticity ne equals the market elasticity e. Demand and commodity prices reflect the same "competitive conditions" for the individual pipeline as for the market as a whole.

On the whole, prices for gas to industries seem to have been set with regard to individual seller demand elasticities ne_i higher than market elasticities e_i, in keeping with some pipeline rivalry. This is to suggest that the number of pipelines at any industrial consumption location does make a difference for the level of prices there -- that n is between 1 and 2, and price differences are reducec by as much as one-half, because of this number. Two-part tariffs seem to be set for retail utilities, with the marginal price to the retailer designed to induce sales at all prices in excess of marginal costs, without regard for individual seller demand elasticity. The tariffs effectively follow the design for monopoly and discriminatory pricing. This is important for the analysis of regulation, since it leads to two conditions: (1) the industrial elasticities contained in a,b in the relative price equations are within the range -3.0 to -5.0; (2) the retail gas utility elasticities contained in a,b for retail equations with commodity prices are effectively infinite; but the commodity and demand charges together

imply close conformance to retail market elasticities within the range -1.0 to -2.0.

The Testing of Regulated Against Unregulated Prices

The expectation is that profit or rate of return regulation increases the prices of regulated sales relative to unregulated sales. The more stringent the regulation -- the closer gross revenues come to real economic costs, or the closer the allowed rate of return on capital comes to the marginal economic costs of capital -- the more apparent the relative price difference should be.[28] The place to look for these effects is in the coefficients a,b in $P_1 = aP_2 + b(\partial C/\partial q_1 - \partial C/\partial q_2)$, since $a = f[1/(1+\lambda),e]$ and $b = f[(1+\alpha\lambda)/(1+\lambda),e]$ and λ takes on two sets of values, the first ranging from zero without regulation to -1 with the rate of return set exactly at the marginal cost of capital, and the second ranging from less than -1 (when regulation is so severe as to force the pipeline to operate in the inelastic portion of the retail demand functions). Now that the elasticity factors e in a,b have been estimated, the approach to finding the regulated price effects is to estimate a,b and then estimate λ with these a,b and the e calculated values.

The full sample of contracts of seven pipelines with industrial and retail utility buyers can be used to fit a regression of regulated marginal price P_1 on unregulated unit price P_2^*, the difference in costs of transport $(\partial C/\partial q_1 - \partial C/\partial q_2)$, and a

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[28] Cf. W. Baumol and A.K. Klevorick, *op. cit.*

constant. In this least squares equation

$$P_1 = aP_2^* + b(\partial C/\partial q_1 - \partial C/\partial q_2) + d_1L_1 + d_2L_2 + d_3L_3 + d_4L_4 + d_5L_5 + d_6L_6.$$

The constant term is a series of dummy variables, $L_1, \ldots, L_6$ for six of the seven pipelines (to account for the effects of differing field gas purchase prices on the absolute levels of resale regulated prices).[29] The observations have been paired randomly to make up a sample of 986 residential/industrial transactions and the least squares regression from this sample is:[30]

$$P_1 = 0.850P_2^* + 0.554(\partial C/\partial q_1 - \partial C/\partial q_2) - 2.768L_1 - 11.221L_2 - 6.259L_3 - 6.419L_4 + 10.691L_5.$$

The price relationship would seem to show lower prices on regulated sales, and low price markups on increased transport costs on regulated sales. But when account is taken of estimated elasticities, the regulated prices are probably not greatly affected, and probably not in the suspected direction. With

$$a = \frac{1}{(1+\lambda)}\left[\frac{1+ 1/e_2}{1+ 1/e_1}\right]$$ and $e_2 = -3.0$, $e_1 = -\infty$, then $\lambda = -.22$, and

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[29] The logic of this can be seen from separating pipeline costs into (a) field purchase price, and (b) transmission costs, and then deriving first order conditions for maximum profit resale prices. The field purchase price enters as a constant in the expression for P_1. This constant will differ for each pipeline.

[30] This regression was fitted with P_2^* as the dependent variable as follows:

$$P_2^* = \underset{(0.057)}{1.176}P_1 - \underset{(0.117)}{0.652}(\partial C/\partial q_1 - \partial C/\partial q_2) - \underset{(0.739)}{3.276}L_1 + \underset{(0.542)}{13.202}L_2$$

$$\underset{(0.729)}{7.364}L_3 + \underset{(0.853)}{7.584}L_4 - \underset{(1.0306)}{12.577}L_5; \quad R^2 = .493.$$

The reason for the reversal of variables was that more serious errors in data were expected to occur on unregulated sales, and these could better be relegated to the dependent variable. The sixth dummy variable was deleted because of few transactions involving that pipeline; rather these observations were combined with those for the first pipeline to form the "base" price differences.

F.P.C. rate of return controls have succeeded in increasing relative prices on regulated sales by as much as one-fifth the extent in keeping with "severe" regulation ($\lambda \leq -1$). On the other hand, if $e_2 = -5.0$ and $e_1 = \infty$, then $\lambda = -.06$ and the effects from regulation have been negligible. Within the range of "reasonable market demand conditions," the effects from regulation have been moderately price increasing, when the comparison is made across regulated and unregulated prices.

The process of regulatory control might be viewed here as taking place in two steps. First, price setting under regulation involves universally the installation of two-part tariffs, with substantial initial charges but with relatively low marginal charges. The reduced marginal prices appear to be lower than comparable average prices on unregulated sales. Second, the rate of return review procedure raises the marginal regulated price above the level that that marginal price would have without regulation. The second step can be said to involve the relative price effect from regulation.

The other parts of the equation are revealing of the price-setting process, and perhaps of the effects of profit regulation, as well. The coefficient b for $(\partial C/\partial q_1 - \partial C/\partial q_2)$ appears to be quite small -- there seems to be much less price variation with distance than called for by "costs of transport" differences. This could be entirely a matter of appearance,

caused by misestimation of $\partial C/\partial q_1$ and $\partial C/\partial q_2$. Another explanation could be that the value of α, the portion of costs allocated to regulated sales, is very high; since $b = [(1+\alpha\lambda)/(1+\lambda)]\cdot[1/(1+ 1/e_1)]$, with $e_1 = \infty$ and λ estimated from a, the standard value of α would have to be greater than 100 percent. This is to suggest that all costs have been allocated to regulated sales -- not inconceivable, but not a likely interpretation of present practice. The third explanation comes from closer examination of the data: it appears that sales at the "farther distance" are predominantly sales to retail public utilities, and the relatively lower marginal or commodity prices on these sales are confounded with the "distance" effect.[31] That is, with moderately effective "rate of return" regulation, then the b coefficient should be "too low". In fact, it is too low, so that the results of discrimination under regulation appear in this second coefficient.

There are a few further tests possible with the remaining coefficients. The different pipelines have entirely different price levels for home sales, perhaps because of different degrees of regulation applied by the F.P.C., but more likely because of

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[31] The variables, P_2^*, $\partial C/\partial q$, confound attempts to measure the effects of more complicated regulatory procedures, such as direct "rate of return" regulation. Further work will have to be done to deal with complicated cost allocation and rate of return regulation directly, because the relevant variables when specified turn out to be collinear with the transport cost variables used here to find b.

historical chance as to the prices paid in the purchase of field supplies of gas. Earlier pipelines paid lower prices for gas supplies than pipelines constructed later, and with these earlier prices still in effect the final sales prices are going to be lower.

The price differences between retail consumers and particular buying industries are similar to those shown by the pooled industry-retail sample. But the "retail-particular industry" differences all tend to show some effects from regulation specific to that industry. For unregulated prices to buyers in the chemicals and stone-clay-glass industries, versus regulated prices, the regression equations were as follows:

Chemicals, N = 38

$$P_2^* = \underset{(0.065)}{1.576}P_1 - \underset{(0.454)}{1.714}(\partial C/\partial q_1 - \partial C/\partial q_2) - \underset{(20.440)}{45.493}L_1 + \underset{(18.387)}{50.294}L_2$$

$$- \underset{(23.777)}{7.476}L_3; \qquad R^2 = .687$$

Stone-Clay-Glass, N = 35

$$P_2^* = \underset{(0.082)}{1.459}P_1 - \underset{(0.513)}{1.828}(\partial C/\partial q_1 - \partial C/\partial q_2) - \underset{(26.664)}{46.388}L_1 + \underset{(24.545)}{56.086}L_2$$

$$+ \underset{(31.383)}{1.382}L_3; \qquad R^2 = .644$$

which imply values of λ somewhat lower than those derived from the all-industries-all-retail regression: here $\lambda \approx 0.04$ for $e_2 = -3.0$, and $\lambda \approx +0.26$ for $e_2 = -5.0$. There would seem to be no effects whatsoever from regulation of prices to retailers, when these are compared to prices on industrial sales in the chemicals and

glass industries. The equations for direct pipeline buyers in the electricity and metals industries versus retail utility buyers show more effects, however. They are as follows:

Electricity, N = 27

$$P_2^* = \underset{(0.092)^1}{1.015P_1} - \underset{(0.547)}{0.493}(\partial C/\partial q_1 - \partial C/\partial q_2) + \underset{(30.034)^1}{13.865L_1} + \underset{(24.948)^2}{149.650L_2}$$

$$+ \underset{(25.368)^3}{31.237L_3}; \qquad R^2 = .841$$

Primary Metals, N = 37

$$P_2^* = \underset{(0.045)^1}{0.858P_1} - \underset{(0.886)}{0.432}(\partial C/\partial q_1 - \partial C/\partial q_2) + \underset{(27.985)^1}{147.609L_1} + \underset{(31.974)^2}{215.586L_2}$$

$$+ \underset{(29.999)^3}{215.448L_3}; \qquad R^2 = -.307 \;.$$

These two regressions show stronger λ effects from regulation, given that the values of the a coefficients are lower. The coefficients for P_1 imply values of λ from -.35 to -.45, and this can be interpreted to imply that one third or more of "substantial regulation" was felt here.[32]

The basic question -- whether regulation raised relative prices -- cannot be dealt with unless the influence of the two-part

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[32] There is no reason for regulation to appear to be more stringest from one sample regression to another, given that the only differences between samples are in the unregulated industries with which comparisons of regulated prices are being made. Rather, the rationale might be that, in particular industry regressions, we are observing price variations having to do with particular competitive conditions in these samples of unregulated sales -- conditions not directly incorporated in measures of elasticity of demand. This rationale takes away credit given to "regulation" that is due to "competition" in the unregulated markets.

tariff is separated from the effects of rate of return controls. This is necessary because there may be a number of reasons for two-part tariffs on sales to retail utilities. They are in keeping with state regulatory requirements on the buyers' resale prices. It is conceivable that they serve as an institution to provide "peak-load" insurance at the cheapest rate. To make the two-part tariff a result from F.P.C. regulation alone confuses the assessment of that Commission's activities.

Separation is not possible, because the two-part prices are the only prices available -- there is no set of single-price regulated sales with which to compare single-price unregulated sales. Only the crudest of indications can be formulated of the effects of rate of return regulation alone. This comes from comparing average revenue P_1^*, the average of initial and commodity charges weighted by volumes delivered, with the unregulated unit price P_2^*; this "price" P_1^* could be considered the "equivalent" one-part tariff given that the F.P.C. set rates of return on capital so that the same profits were made as are now collected under the two-part tariffs. The equation $\{P_1^* = aP_2^* + b(\partial C/\partial q_1 - \partial C/\partial q_2) + d\}$ would show the price-increasing effects from regulation in the a,b coefficients.

This equation has been fitted to the 986 observation sample of pooled industrial-retail utility sales in 1969. The regression is as follows:

$$P_1^* = 1.081 P_2^* + 0.745(\partial C/\partial q_1 - \partial C/\partial q_2) - 2.055\ L_1 - 13.859 L_2 - 3.209\ L_3 - 5.785\ L_4 - 2.815\ L_5$$

indicating higher relative prices for regulated sales than shown in the marginal price comparisons.[33] But this is deceiving, because the implied values of λ have to be much closer to zero in this case given that the assumed elasticity of e_1 -- without a two-part tariff -- lies in the range from -1.0 to -2.0. In fact, the estimated values of λ are positive, ranging from .48 for $e_2 = -5.0$, $e_1 = -2.0$ to 5.8 for $e_2 = -3.0$, $e_1 = -1.1$ so that the measurable effects from rate regulation alone are non-existent. To be more specific, these effects are contrary to expectations from the theory of the constrained firm, since the theory shows "no effect" for values of $\lambda > 0$.[34] All that can be said with these findings on P_1^*, P_2^* is that the effects from profit regulation alone are most likely negligible.

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[33] The fitted equation was

$$P_2^* = \underset{(0.083)}{0.925 P_1^*} - \underset{(0.132)}{0.689}(\partial C/\partial q_1 - \partial C/\partial q_2) + \underset{(0.856)}{1.901\ L_1} - \underset{(0.642)}{12.827 L_2}$$

$$+ \underset{(0.854)}{2.969 L_3} + \underset{(0.981)}{5.351 L_4} + \underset{(0.981)}{2.604 L_5}; \qquad R^2 = .365.$$

[34] There are, of course, other alternatives than designating the calculated P_1^* as the regulated unit price. There is little chance that, given a regulatory profit constraint, the pipeline sellers of gas would charge the price exactly equal to the average revenue from the two-part tariffs.

This conclusion must be brought together with those from the P_1,P_2^* equations, and those from the earlier price equations on industrial sales free of the effects of regulation. The assessment of P_1^*,P_2^* alone is quite tentative, since it is not possible to define precisely what is being measured by "price" in the average revenue equations. But it does not contradict earlier assessments. Overall, the effects of regulation are shown by calculated values of λ in the range from 0.0 to -0.3; the first value implies no effect from regulation, and the second that there has been some creation of price disparities by regulation. In economic terms, there has been a tendency towards higher relative prices under regulation, but not a strong tendency. Prices charged by pipelines on regulated retail utility sales and on unregulated industrial sales tend to vary with costs of transport, with elasticities of demand, and with the field purchase prices of gas transported by the different pipelines. Prices at the margin on regulated sales are lower when there are two-part tariffs; but after accounting for the effect of the two-part tariff, the marginal prices for regulated sales are greater than on unregulated sales. That is, after taking account of *strong* tendencies for prices to vary with costs, with demand elasticities and with tariff structure, prices seem to be only *somewhat higher* on regulated sales.

A Summary Assessment of Profit Regulation

The various price control initiatives of the Federal Power Commission, and the response of the companies, appear to have had little effect no matter the dimension in which they have been measured. The initiatives of the Commission have been consistent and prolonged, in terms of litigation expense and delay. But the results of these initiatives have not been discernible. One year's experience in price reviews and surveillance seemsto have resulted in price reductions not much greater than the cost of litigation. Even then, the reductions were from levels sought by the companies in their initial submissions of rates, and there may have been many reasons for submitting artifically high initial levels. In the long run, the actual transactions prices on regulated sales would not appear to have been consistently different from those on unregulated industrial sales, after account had been taken of differences in costs of transmission or in demands for natural gas. In the long run, there have been no claimed differences in electricity prices attributable to interstate wholesale power regulation. The absolute value of Federal Power Commission price setting activities has been either very low or negative.

The implications of these poor results are many and diverse, but they must include changes in policy on profit

regulation. Profit or price regulation might be abandoned, to save the costs of litigation at the expense of negligible price increases. This is not a convincing proposal as it stands. There are many possible results from abandoning regulation that have not been explored -- some of which could be worse on the same absolute "benefit-cost" measures as those used in evaluating profit regulation.

There would be extensive savings in economic costs from eliminating litigation and from reducing the many delays accompanying Power Commission proceedings on rates. But there could also be changes in market conditions that would be as costly: state commissions could enter the regulatory vacuum, extending their jurisdiction in order to "protect the interests" of retailers they already regulate; alternatively, pipelines might take advantage of particular situations of extensive market power not now revealed under regulation. The proposal to eliminate regulation must be made on the basis of evidence on the market and public policy conditions _in the absence of present regulatory forms_.

Alternative methods for setting "unregulated" prices are evaluated in the last chapter of this study. The purpose is to find simpler procedures, with lower costs of regulation for both the government and the consumers of gas and electricity.

More important, the goal is to find applicable techniques for adding to the quantities, and reducing the prices, of natural gas and electricity.

4. Improving the Organization and Performance of the Utility Industries

In the last half-century, Congress has turned to the independent regulatory commission form of government to solve many problems. Indeed, at the various times when legislation has been offered to start a new commission, it would appear that the commission form was going to solve all of the problems of the transportation, energy and communications industries. There has been a tendency to seek to achieve two goals -- that of price or rate reduction for the provision of cheaper service to the consumer, and that of furthering the "growth and development" of the industry being regulated.

These goals could have been quite diverse, if not inconsistent. In some commissions, the furtherance of "development" seems to have been interpreted to require the protection of established firms against competition in that industry, and the creation of circumstances in which profits are maintained at a level above the cost of capital. It is difficult in these cases to point to such achievements and to reduced rates to the final consumer at the same time.

The Federal Power Commission has been given such a double mandate, to regulate interstate wholesale rates for natural gas and electricity, and to promote or develop the transmission and sale of these forms of energy. The Commission

has authority to set standards for service in natural gas transmission, and to require line extensions in service areas so as to expand coverage of the natural gas pipelines. Authority to improve or develop service in electricity is much broader. Under the Federal Power Act, the Federal Power Commission was given the responsibility under Section 202(a) "of assuring an abundance of supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources." This provided a mandate for setting service standards on transmission, and for requiring additional facilities to assure "an abundance of supply of electric energy."

A great deal could have been done with this mandate in the last few years. If the Federal Power Commission had operated in a fashion similar to the Civil Aeronautics Board, the "promotion of the industry" activities could well have dwarfed in importance the "case process" for calculating rate base and rate of return for controlling prices of electricity and gas. In fact, the Commission has done very little towards industry promotion in either gas transmission or electricity production. What has been done is open to conflicting interpretation as to whether it is of the nature, and the required extent, of the original mandate.

The view shall be taken here that the original purposes for "assuring an abundant supply" were complementary to rate

regulation. This will be explained in some detail in the next section. Thereafter, the results in these terms will be evaluated, first by outlining what could have been done especially by the Federal Power Commission, and second by showing the actual extent of Commission activities. The extent has been limite

Assuring an Abundant Supply

The electric power and natural gas industries may not provide exactly the right amounts of service to final consumers. The prevention of firms from charging unregulated prices that are "too high" is the most quoted motive for regulation, and to the extent that the goal is achieved -- so that there is some reduction of prices -- there are increases in quantities demanded. There are also a number of other reasons why outputs may be too small, as well as some reasons why it may be too large, when decisions are left entirely to unregulated companies. The production of "too little" power, or the transmission of "too little" natural gas, could be the result from inefficient scale of the individual enterprises relative to the market or industry as a whole. There may be advantages of larger scale firms in meeting the varying demands of diverse groups of consumers over time and in developing new technologies to better serve these demands. It is also conceivable that markets themselves are not well defined, and that a reorganization of industry levels or a change in the nature of specialization of

firms could increase production and sales without increasing capital or fuel expenditures. But there are other conditions implying "too much" output. Capital and fuel expenditures may be "too low" in the sense that they do not account for all of the costs that the industry imposes on the environment and on users of energy. If costs are not correctly accounted for, but are too low, then the impact of price regulation may be to increase quantities demanded beyond the efficient level.

These are all matters of substantial controversy. There are cost savings to be captured at various levels of the energy industries, from changing the scale and degree of integration of firms and from developing new technology amenable to the new scale. There are very large numbers of documented cases of costs of environmental degradation imposed by the electric power and natural gas companies on other individuals besides the specific consumers of these outputs. There are even some indications as to what might be done as a result of reorganization of these industries. The controversy arises on whether the Federal Power Commission is the proper vehicle for bringing about these changes, and whether much could be expected from the Commission if it were found to be proper and were given the mandate. This rests on what can be done, and on the history of what the Commission has done to this point in time.

The gains from systems pooling are widely acknowledged to be important, and are also acknowledged to extend beyond present boundaries of individual companies. These go beyond the economies of scale apparent at the three levels of the industry. At the final or "distribution" level, one set of distribution lines is sufficient to serve the individual dwellings in any community at any level of demand, and a single system per community is also sufficient. At the transmission level, there are obvious gains against line loss from transmitting electric power or natural gas in a single delivery system (up to capacity for 1 million residents, at the least). The production of electric power would appear to be subject to scale advantages as well; there are indications from cost function and production function studies that there are savings in expenditures per kilowatt-hour up to capacity limits of 1 million kilowatts; at the least, there is some evidence establishing an initial finding that the elasticity of total generating costs with respect to unit size was in the range from .8 to .9 in the 1960's, up to the 1 million kilowatts level of capacity.[1] Fully integrated electricity generating companies, with facilities for production, transmission and distribution, would be able to

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[1] Cf. W. M. Capron, (ed.) Technological Change in Regulated Industries, chapter 3, W. R. Hughes "Scale Frontiers in Electric Power," p. 48, and the references cited on p. 50.

take advantage of economies of scale in delivering a constant load to communities as large as those having populations of 1 million.

The demands for electricity, however, are not constant over the hours in a day, or the days of the week, or over the seasons of the year. Demands in different cities are greatly different at any point in time, and as a consequence there are significant cost savings from capacity elimination in "matching" high demands in one city with low demands in the other, so as to provide lower total or joint capacity to meet these demands.

The amount of actual capacity available for use by a producing company varies from time to time, because of equipment outage; the proportion of unavailable capacity can be reduced by increasing the scale of a system, or by operating a number of systems across markets in a coordinated way. The failure of a large scale (1 million kilowatt) generator to operate on schedule is likely to occur with a probability α and a "safety margin" of additional capacity is required to reduce the probability of consequent outage for the entire system below α in most instances (say, to $\alpha - \beta = \gamma$). The proportionate size of the safety margin required to reduce the probability to γ can be made smaller if a number of large generators are "pooled" to form area-wide capacity, because "pooling" with shifts of usage of m units of spare capacity from one area

to the other reduces the probability of outage of the generator serving one metropolitan area from α to $(\alpha)^m$, (given that all m units have to be out when capacity can be shifted).

The gains from taking advantage of "demand diversity," and of pooling of "safety margin" capacity, conceivably could be very large in terms of dollars of cost savings and consequent rate reductions. The Federal Power Commission in its 1964 National Power Survey documented these gains at great length. Demand diversity was shown (in chapter 13) to be a result of extremely large seasonal diversities in home and industrial consumption of electricity, related to weather and to seasonal differences in industrial production. These did not occur at the same time of the year, however: the National Power Survey showed that there were capacity demands of 7 million kilowatts more in December over August in 26 Federal Power Commission supply areas, but also capacity demands of the same scale in 22 other supply areas for August over December.[2] The hour-by-hour demands of consumers on individual power systems vary greatly as well, and, most important, the peak demands do not occur in the same hour given that there are four regional time zones in the country. This is particularly in evidence in the

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[2] The National Power Survey, a report by the Federal Power Commission in 1964, U.S. Government Printing Office (October, 1964), p. 176 and Figure 101.

winter months, when demand peaks occur in the hours between 5:00 and 7:00 P.M. -- the peak has passed in the Eastern time zone when it is occurring in the Midwest, but has failed to begin in the Far West. The operation of capacity across regions in a unit production plan, but where there are different seasonal peaks and different time zones, would allow the capacity at one location to be used during its off-peak periods to provide some part of the peaking capacity at other locations. According to National Power Survey estimates, if individual systems were coordinated to form regional groupings coincident with the 8 F.P.C. statistical regions, 14 million kilowatts of capacity could be eliminated from individual generating company margins by 1980.[3] If coordination were pushed to the extent of establishing two national zones, one for the Eastern and the other for the Western half of the country, then 34 million kilowatts of capacity could be eliminated from expected or forecast margins for that year.[4] The coordination of the entire nation, presumably by the establishment of a national power grid and unit operation of all production facilities, would save 41 million kilowatts of capacity by using peaking facilities at one location to cover peaking demands at the other during the first

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[3] Cf. National Power Survey, Table 49, p. 183.

[4] Ibid.

location's non-peaking periods.[5]

The spare capacity of reserves that are held to cover the forced outage of base-load equipment, or that are held to be put into service during maintenance periods for the base-load equipment, can be reduced by approximately one-half with a policy of systematic inter-system coordination. The exact amount of the reduction depends upon the standards set for system reliability -- for that probability of outage which is tolerated, leading to consequent failure to provide service to the final consumers. The National Power Survey, utilizing a conservative standard of a loss of safety margin from a generator failure once in five years corresponding to a "loss of load" probability once in ten to fifteen years, showed substantial reductions in the proportion of capacity required for reserve as a result of coordination, as well as gains from the relaxation of the safety margin constraints operating against the installation of the most efficient sizes of generating unit. The illustrative conservative case of coordinated systems consisted of five systems, operating separately with 20 generating units in each system, required a total of 3 reserve units in each system. But if the systems were to form a pool, only 6 units were required for reserve and the saving in capacity requirements was equivalent to 9 equal-sized generating units.

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[5] Ibid.

This followed from the non-coincident outages at specific locations in the consolidated or fully coordinated joint system being covered by shifting the capacity use in the previously separated reserve margins.

From the example cases, the required reserves for forced outage were estimated for each of the F.P.C. power regions, for two time zones and for nation-wide coordination. The progressive formation of larger coordinated regions is shown to reduce safety margin capacity by about 5 percent of total peak capacity. If coordination were to extend to the point where there were only Eastern and Western zones, or to country-wide unit operation, upwards of 7 million kilowatts of reserve capacity would be eliminated.[6] There would be partially compensating disadvantages of such thorough coordination, in reduction of opportunities for scheduled maintenance during off-peak months (since there would be less off-peak time in which to repair unused capacity). But, on the whole, considering both the gains from demand diversity and non-coincident forced outage, the total capacity saving from coordinating systems according to four sectors, two sectors, or country-wide unit operation should be of the order of 35 to 50 million kilowatts.[7] The sum total value, in terms

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[6] According to the National Power Survey, op. cit., p. 196.

[7] The National Power Survey, op. cit., Table 53, p. 197.

of annual cost savings, from the safety margin and load diversity reductions come to approximately $1.1 billion per annum by the end of the 1970's.[8]

These estimates have been reaffirmed in more recent findings on cost reductions from coordination. The research of William R. Hughes takes as given that the outer limits on the gains from coordination can be defined by the "best coordination actually achieved": the maximum efficient planning unit is "the minimum optimum scale associated with the level of coordination already shown to be feasible."[9] On the basis of this benchmark, an industry with 20 to 30 major planning units of approximately the same size would achieve a level of coordination able to capture economies of pooling peak load and safety margin capacity. This is a "size range of planning units equivalent to that of the five or six largest United States systems (a 20-unit industry implies an average size of major planning units slightly smaller than the Tennessee Valley Authority, the largest U.S. system).[10] Firms of this size, able to capture the economies of full generator size and of pooling account for only 21 percent of present industry generating capacity; movement by merger and coordination towards achievement

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[8] Cf. National Power Survey, Tables 78 and 79, for capacity reduction items 1 and 2 in Table 78.

[9] W. Capron, (ed.), op. cit., chapter 3, p. 74 et al.

[10] W. R. Hughes, in Capron, op. cit., p. 76.

of this scale for 100 percent of capacity would be in keeping with attaining "an abundance of supply of electricity."

The maintenance of competitive market structures is widely considered to be an end in and of itself, or at least a prerequisite to the provision of "an abundance of supply of electricity." Competition could be a substitute for regulation, given that the existence of a large number of sources of alternative supplies prevents the occurrence of the excessive price-cost margins that regulation seeks to dispel. An appeal sometimes is made for large numbers of production and distribution companies in the electricity and gas industries even if they are not competitive. For example, it is asserted that "it is important to have institutional diversity so that we can determine the difference in costs of service, typical bills, and other operational factors and use these as checks in gauging the impact on the consuming public. .... The coexistence of intersystem reference points permits the small systems to act as a counterweight to offset segmented state commission regulation and the political and economic power of the large systems."[11]

These gains from either competition or company pluralism are difficult to quantify, and are not going to be realizable

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[11] Statement of David S. Schwartz, Assistant Chief, Office of Economics, The Federal Power Commission, in Hearings before the Subcommittee on Antitrust and Monopoly of the Committee on the Judiciary, United States Senate, 91st Congress, 2nd Session, pursuant S. RES. 334 "Competitive Aspects of the Energy Industry" Part 2, p. 558 (June 9,10,11, 1970).

to any great extent when there is systems pooling and coordination. There are approximately 1,000 private, cooperative, Federal, and REA generation and transmission companies in the electricity industry (some of whom also carry out retail distribution activities). Competition among generating companies could be said to take place when they provide alternative sources of capacity for service to a particular retail distribution company -- when each offers the retail distributor the use of capacity on the basis of competing prices for electricity at wholesale. It is not conceivable that prices could be competitive when these companies are all part of the same power pooling operation; coordination to the extent of reducing individual company safety margins would require the companies to operate in much the same way as production units of a single regional firm, and this is antithetical to competitive bidding within the region for the business of one of the independent retailing companies. Similar conditions exist at the final distribution level of the industry. There are approximately 2,400 distribution companies, the majority (close to 1400) being public enterprises and most of the rest being members of the Rural Electrification Administration. These companies all have local retailing monopolies, so that there is no competition

between any two of them of any extent at the present time.[12] The creation of local retail competition for the patronage of a final consumer would require important losses in economics of local scale, and this has not been proposed in any case.

The limits on potential gains from pluralism are shown by the policy alternatives themselves. The first proposed alternative is to design rate structures that allow the smaller retail distribution companies to become members of power pools or to buy from power pools without having to pay higher discriminatory prices.[13] This is in effect a proposal for price and profit regulation that calls for a finer degree of regulation than hitherto practiced by the Federal Power Commission. It would not seem to be a new and important plan, separate from many suggested "reforms" for profit regulation. At least the problems raised by present regulation would reoccur if even more complex procedures are put into effect in the setting of individual

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[12] There could be competition for the supply to energy-using companies or individuals who would transfer from one monopoly retailing region to another, given a favorable difference in the price of energy. This is conceivable for a very small number of large corporations producing final products with a very high energy component -- for those few corporations who are essentially going to be in the business of consuming energy. There is widespread agreement that these high "energy mobility" companies do not constitute a significant proportion of total demands for electricity at any location, so that they will not affect price-cost margins at the generation and transmission levels.

[13] Statement of D.S. Schwartz, op. cit., pp. 566-67.

prices, and these problems would seem to weigh against expecting any significant new gains in efficiency (different from those shown in chapter 3). The second proposal is to make certain that "small systems [have] access to all power pools ... to allow them to own a fair and reasonable portion of any proposed nuclear plant."[14] This is of very limited social value, because it adds to the membership in the pool without reducing system-wide costs from reduced safety margins, while at the same time it has no effect on competition among members of the pool. The (local monopoly) retailer gains access to power not at wholesale price but at marginal cost, but does so by becoming a member of the group that sells power at prices in excess of marginal cost. Even though vertical integration makes the sales in this case internal transfers from the retailer's own wholesale level to his own retail level, the opportunity to take an excess profit margin is still present through the form of charging a fictitious "full" wholesale transfer price. There would seem to be no lasting gains from a more pluralistic market structure except from the pure numbers involved in pluralism.[15]

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[14] Statement of D.S. Schwartz, op. cit.

[15] As for the "pure numbers" gains, there is no basis on which to find greater gains from pluralism at the level of 3,500 firms than there would be at the level of 35,000 firms or 300 firms for that matter.

Environmental and research aspects of the "abundance of supply" are matters of industry-wide investment in new techniques, versus company investment in orthodox plant and equipment. No one has estimated how much additional investment would be required to meet demands for capacity in the coming 30 years, but just for generating equipment alone, there will have to be more than $400 billion of new expenditures between 1971 and the year 2,000.[16] The investments in finding and developing new fuel resources will have to exceed $300 billion.[17] These outlays would only be a minor portion of the costs of capacity to meet demands; increased use of land, air and water resources around and in urban regions would be required as well. These costs have not been included in forecast capital and fuel expenditures because, in the absence of well-functioning markets for the environment, consumers as a group bear most of them. They are extraordinarily difficult to calculate because of the absence of markets either to purchase those resources, or to do away with the effects of industrial use of them; there is certainty only that they are going to be large enough to have an effect on political decisions.

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[16] Cf. P.W. MacAvoy, Economic Strategy for Developing Nuclear Breeder Reactors (MIT Press, 1969).

[17] Cf. Fortune Magazine, May 1970, p. 70.

The "internalization" of these natural resource costs by consumers could create excess demand problems. Governments now hear more and stronger objections of minority groups against the construction of new generating plants by electricity companies, or new pipelines by gas companies, and the nature of the response most often now is to delay or disallow the investments. The final result of rulings of this nature could be a state of permanent excess demand. In economic terms, regulatory prohibitions against the use of natural resources by energy and communications companies could prevent the achievement of levels of investment required to clear markets at prices close to present levels.

There is an economic policy for preventing or at least relieving excess demands. In face of prohibitions against the use of natural resources, those making research and development plans could orient new work towards innovations in resource-replacing capital equipment. There are candidate projects for developing such types of equipment. The promising avenue for research to follow is not towards finding ways to estimate and charge the costs of land and water rights, although this work is worthy even if it looks impractical at present, but rather to find new technology in capital equipment that relieves the demands for these natural resources.

In fact, the technology in the energy industries would

seem to be little different now from that some years ago.[18] There seems to have been substantial progress, from higher load factors or larger scale for the single producing unit, resulting in productivity increases of 3 percent to 5 percent each year.[19] On other dimensions there has been little progress; the techniques used for energy conversion in electricity production are the same now as they were 50 years ago. These are natural resource using, in the sense that there were alternative techniques also available 50 years ago that if used would have resulted in substantially greater capital investment and less fuel, air, and water utilization. Progress will have to be the development of new technology that, when put in operation, costs more or less in total dollar outlay but much less in non-monetary social expenditures on natural resources.

There are development projects now operating at low levels that could accomplish this. They differ greatly in the problems to be solved -- some are in the behavior of materials at 4000°F or at -450°F, or the behavior of large scale or complex systems. All have histories of promising first-stage development results in one or two companies, but a lack of commitment to

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[18] The best analyses of technology, in the reports and papers of the national laboratories such as at Oak Ridge and Los Alamos, and of the university-affiliated government laboratories, are testimony to the need for precise description in order to make new developments; but none generalizes on the extent of innovation in equipment and systems in these industries. The lack of review material itself seems to be testimony to how very little new application of science there has been.

[19] Cf. W.R. Hughes' chapter on electric power in W. Capron, editor, op. cit.

second-stage test modules or prototypes, where the commitment involved large financial outlays and inter-company cooperation. There are three considered here. (1) the generating of electricity by MHD (Magneto-hydrodynamics), a technique centering on obtaining current from passing a gas at 4000°F through a magnetic field, has had a long laboratory history and commitments of several million dollars through the half-scale prototype stage. (2) superconductivity is a technique for obtaining electricity with less of certain natural resources, in this case resources not in generating but in transmission of electricity. Development projects here seek to deliver electricity without line loss over long distances on enclosed rare-metal conduits at -450°F. They are actually important projects in a subsystem of MHD, and are stalled on funding and organizing the same MHD full-scale prototypes. (3) electricity from the breeder reactor has been produced by plants beyond the prototype stage and at the full-scale experimental stage, but only in one very specific coolant technology receiving contract grants from the Atomic Energy Commission. The breeder reactor is a steam generator with a difference -- a reactor that uses the "fast" or unmoderated fission process to produce both heat energy and high productivity plutonium at the same time. The development problems center on maintaining dynamic control of the fission process -- controlling random surges of temperature that displace

fission equilibrium so as to cause melting of the reactor core -- but there are problems as well of systems development in the cooling medium that are critical for plant economics. These latter problems differ for a helium-cooled system from a liquid sodium-cooled system, and the A.E.C. has shown interest in solving only the liquid sodium reactor's problems.

These technologies have promise in dimensions not measured five years ago. The MHD generator and the breeder reactor are expected to produce electricity at costs comparable to those experienced in new fossil fueled generators in the middle 1960's. But this is without taking account of elimination of a substantial portion of the social costs of using the air and water resources around the producing plants and the land resources devoted to mining fossil fuels. The MHD generator expects to achieve a 50 percent increase in thermal efficiency as a result of higher temperatures, and expects to operate most efficiently in a closed cycle, with consequent significant reductions in thermal water pollution and in air pollution. The gas-cooled breeder also operates on a closed cycle, and it reduces demands for enriched uranium, to the point that present stockpiles of uranium mining and manufacturing residue ought to serve as the basic "breeding" fuel supply for the rest of the century in this country. The superconductivity development program is not as promising, since the direct dollar expenditure

for replacement of above-ground long distance transmission lines with below-ground superconductivity lines will be substantial. But underground superconductivity transmission would release land for other uses, as underground transmission of gas does at the present time, and such transmission would also increase useful output of electricity from fuel and capital outlays by more than 10 percent by reducing line loss.

The Economics of Development

These technologies will require money, time and an economic strategy to become effective. How should the development programs be organized, and what are the sources and amounts of required expenditures?

The answers so far have been provided by the electrical equipment manufacturers, and the Atomic Energy Commission. They have provided the funds or done the work, a state of affairs that raises more questions than it answers. Are these organizations the right size and do they have the perspective for making decisions on the relative efficiency of alternative development projects? Should the development of each of these new technologies become the responsibility of Government, or industry consortia, or only of certain private companies, on grounds that goals will be reached sooner, and at lower costs?

The answers are a matter of policy research that cannot be completed at the present time, because the information required

for this research has not been made available by those now involved in development projects. The information required is quite specific to the economics of parallel research. This economic analysis begins with assuming that there are numerous competing projects each promising to develop these new technologies, and these must be eliminated by sequential decisions so that, at the last stage of development, the least cost project in each technology survives. This requires m parallel projects at the initial stage, from which $m \geq 1$ are chosen up to the last stage -- but only if cost estimates improve at each stage. More precisely, two improvements are required. First, the expected value $E(c/c_n, c_{n+1}) = c_{n+1}$, where c is the final estimate of demonstration plant cost and c_n, c_{n+1} are estimates of this same cost but at successive earlier stages n and n+1. Second, the squared errors of successive estimates must diminish, or $E(c_n - c)^2 \geq E(c_{n+1} - c)^2$.[20] The decision then is to choose first the project with the lowest forecast costs, and second any other project for which the "looking costs" are less than expected subsequent cost reductions from being able to select the best from multiple projects after one more stage.[21]

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[20] Cf. T. Marshak *et al.*, *Strategy for Research and Development* (Springer-Verlag, 1967).

[21] The "looking costs" are the costs of running that project one more period. Cf. T. Marshak, *op. cit.*, p. 245. This does not hold for m > 3 -- a "striking example of the ability of analysis to refute intuition."

To make these decisions on the breeder reactor would require the development companies to reveal recent changes in design study estimates of the costs of developing breeder fuel and capital. These changes, calculated in a roughly comparable way for different coolant technologies in the *non-breeder round of development* in the 1950's and early 1960's, have been made known after the fact. They showed clear cost savings from parallel research and development, of up to five coolant types;[22] now they have to be calculated *a priori* for the *breeder round of development*. After that has been done, normative propositions can be formulated on the efficient number of parallel breeder reactor projects.

Even at this preliminary stage, however, some propositions on the breeder and on other new technologies can be anticipated. Orders of magnitude of costs, and the nature of research, must imply that the work will have to be done by an organization larger than a few producing companies. The costs of developing any one of these new technologies will exceed more than one billion dollars, even if the optimal parallel project is undertaken. The estimated costs of research and development for a liquid sodium-cooled breeder reactor are now between $1.3 billion and $3.2 billion, while those for a gas-cooled fast breeder reactor

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[22] P.W. MacAvoy, *Economic Strategy for Developing Nuclear Breeder Reactors*, *op. cit.*, Appendix A.

are between $1.0 and $2.8 billion. The optimal combination of parallel projects will likely cost from $2.2 to $4.6 billion.[23] Those for the other technologies extolled above may not be quite as large, although this may be the case because it is still early in the history of making cost estimates on MHD.

Parallelism seems promising in each technology. There are numerous projects proposed towards final construction of an economic demonstration plant in each of the new technologies; the breeder technology may boast three, the MHD technology two or three when account is taken of many possible ways to do superconductivity. The projects will realize substantial changes in forecast costs and performance at least to the full-scale prototype, so that there should be more than one project at least at the next few stages of development.

Given the money requirements and the necessity of parallel projects, no single company could carry on the optimal number of projects in any one technology. There has to be a consortium of buyers, producers, or governments because of (a) the large scale of single projects, (b) the total cost savings likely to follow from taking on more than a single project, (c) the necessity for non-market decisions in the choice among duplicative projects of the final single project.[24]

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[23] *Ibid.*, p. 47.

[24] Marshak, in his discussion of a "decentralized" organization, requires that the many approaches be compared at each stage by a single decision maker. T. Marshak, *op. cit.*

The only organization presenting itself as an efficient consortium at this time is the Federal Government. No other operates at such a large scale in R&D that it does not face the risk of default on all its obligations if parallel approaches in a new technology default. The consortium-Government here could possibly operate as an insurer and banker, by funding research to be carried out by private companies; it might be capable, given the risk that internal politics will protect projects, of making unbiased comparisons of costs at each stage and then weeding out the higher cost approaches. The best way of establishing this presumption is to compare the problems of the Government with those of alternative consortia.

The electricity or gas retailing industries, as a consortium, could form a collection of sub-organizations to do research and development. But would the consortium managers likely choose the optimal research path? Capital markets are not now perfect enough to provide them with funds to do enough research -- at least not enough relative to the Government consortium with its portfolio of many R&D projects. Also, they would not organize correctly. Since individual demands for new technology by the retailers would differ over a wide range -- depending on buyer's scale and the prices of fuels at his location -- an averaging process would have to be applied to all demands. The weighting in the consortium would probably have to account for large numbers

of small firms, so that the "average buyer's demand" for new technology would call for a smaller scale than warranted by new "largest buyers' demands." The second demand would not be chosen, even though offering lower unit costs for the final consumer, in costs of natural or other resources. Rather than the new technology changing market structure, it would be fitted to the prevailing market structure. There is considerable doubt that the companies on the buying side of markets for energy equipment could as a group decide the least-cost staging of multiple approaches to new technology in this industry.

The producers of equipment themselves could form a consortium to carry on research. Here the motivation for cost reductions would be strong, and the scale of research would at least be in keeping with the large scale of the firms on the producing side of these industries. There would be serious problems, however. Given that each company would specialize in a project, the "weeding-out" of projects would require that some companies fail to complete their programs. In effect, the consortium would be required to eliminate members and such decisions would be more or less difficult to make, depending on the way in which the organization was structured. The decisions might well depend upon being able to make side payments to failed firms, and these payments would raise serious problems. The existence of an industry-wide organization to control research

output and render side payments to member firms makes collusion on final production of new equipment possible, and even probable. The economy-wide losses from collusive prices can be greater than the gains from following the consortium's efficient research plan; in the case of developing breeder reactors, these potential losses would appear to be half of the total gains from carrying out parallel research.[25] In any event, the (alternative) Government consortium would not present the problems inherent in research collusion among producers.

The proper organization depends centrally on costs, and on the importance of parallelism in development. More than one approach to solving a development problem will probably be shown to be optimal for cost or demand reasons for the next few years, in each of the technologies mentioned. One company probably cannot afford to complete the new technology.[26] This seems probable, but it is still a bit early to assert that the electricity and gas companies ought not to do any research and development. It is only likely that the Government could and should do it, probably by funding a number of company ventures in competing projects in any one technology and then choosing the best of these.

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[25] Cf. P.W. MacAvoy, Economic Strategy for Developing Nuclear Breeder Reactors, op. cit., chapter 4.

[26] The argument made for parallel research in the study of the breeder reactor was that a portfolio of projects would produce a variety of products, all of which would be demanded at levels justifying the additional expenditures. There were not enough data to evaluate "pure parallelism" on one specific output.

Even here, the proposition as to best organization is not firm and precise, since the "Federal Government" includes the Federal Power Commission, the Atomic Energy Commission, and the various Power Administrations in the Department of the Interior, each with its own constituency. None of these has a strong claim to being the institution for efficient R&D. If the Atomic Energy Commission were to choose projects, given its constituency in the steam boiler industry, little work would be done on superconductivity. The Federal Power Commission's long experience with controlling entry and prices in the gas or electricity transmission industries would not prepare it well for choosing among reactor development schemes.

The best organization for making R&D decisions should be versed in science, and would be located in the Government so as to be able to make comparisons on the use of resources across technologies without answering only to one constituency in one technology. The organization should have responsibility for all R&D expenditures on energy and communications technology. If the assertions made here are correct on what has to be done to satisfy demand in energy forthcoming in the next two decades, and those on the scale of R&D are also correct, then this organization should be provided with a mandate very soon. If this organization is the F.P.C., then much needs to be done to prepare for program formulation.

The Accomplishments of the Commission

In some ways, an independent regulatory commission is particularly well suited to furthering the year-to-year improvements in the quantity and quality of service. The gains from systems pooling and coordination are external to the individual companies, but internal to the industries being regulated, and one specific source of decision making at that particular level of the industry is the Federal Power Commission. Also, this Commission is one of the governmental agencies that can affect the structure of markets and the extent of competition among producing or retailing companies, since the F.P.C. shares with the Securities and Exchange Commission, and the Antitrust Division of the Department of Justice, responsibility for approving mergers between electric power companies or between natural gas transmission companies. The impact that producing companies have on the environment, and on the rate of technical progress in the industry, could be made to depend upon industry-wide rules and regulations which required entities to pay the costs of using all natural and environmental resources. These rules could be determined in part, and certainly enforced in part, by the Federal Power Commission as part of its activities on certification of new capital equipment; and the Commission could well make new rules on pricing to reduce pollution or to foster development of advanced technology.

The question is, what has the Commission actually done to enhance the quality of service? Specific actions have been taken on systems pooling, on competition among producing companies, and on the environment -- actions in the form of case decisions, or by Commission order. These have had limited effect, particularly when compared with what the Commission could have done by following readily available alternative courses of action.

Progress in systems pooling and coordination in the last five years has taken place within an atmosphere of F.P.C. permissiveness and even exhortation. The Federal Power Commission centered its attention on systems coordination in the aftermath of the New York City-Northeast power failure in November, 1965, when directed by the President to analyze this regional blackout and to find means for preventing any reoccurrence. The F.P.C. not only wrote an analysis of the power failure, but proceeded in subsequent months under the authority of Section 202(a) of the Federal Power Act to encourage the adoption of more stringent design criteria for large scale generators, of new techniques for shedding load in emergencies, and of increased interconnection and coordination of facilities. The Commission has continued to practice encouragement. A statement on Policy Reliability and Adequacy of Electric Service was issued in June

1969, and amended in 1970, calling for an expanded informational reporting program, for Federal participation in regional electric reliability councils (in a non-voting and advisory role), and for network load flow analyses and projections for all systems over a ten year period. This statement, and the meetings and low level participation in the reliability councils that followed, cannot be considered to be "taking charge" -- rather, the Commission has fostered voluntarism in the interconnection of companies in the same state or within adjoining states.[27] This is made clear by the Commission's own statement of its position: "The Commission believes that the stated goals (of achieving systems reliability) can best be achieved by strengthening the regional reliability councils and related organizations which have been established to further reliability and adequacy of power supply, by the participation on a non-voting basis of staff representatives of the Commission...."[28] This is to call forth "careful attention to advanced planning and the reporting of data" by the producing companies themselves on a voluntary basis. It did not call for the Commission assuming a decision-making role in the reliability councils, or requiring

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[27] Cf. F.P.C. Statement of Policy Reliability and the Adequacy of Electricity Service, Order No. 383-1 (January 13, 1970).

[28] Ibid., Order No. 383-1 (first revision), p. 3.

reluctant companies to become members of the councils and to interconnect with members of the councils.

Beyond its administrative rulings, the Federal Power Commission has constructed a large body of case law on systems reliability in the last few years. The Commission has been expanding its jurisdiction through licensing procedures to cover additional wholesale sales, partly as a means by which to add to Commission coverage of interstate pooling arrangements. Most of the new coverage is on old power facilities constructed on interstate waterways previously considered to be exempt because they were on non-navigable parts of the river (before the Taum Sauk decision [381 US 90]). This is narrow additional coverage -- gaining jurisdiction over small water power projects -- but it was motivated by a desire to consolidate licensing as much as possible so as to add to the efficacy of regional plans. This is shown in Central Vermont Power Company, 81 PUR 3d 334 (1969), where the Commission stated that their main interest in backdating licenses was to minimize inequities arising from the operation of previously constructed projects that were unlicensed, where these projects became part of regional pools containing licensed projects.

But while extending coverage over this rather narrow functional group of producers, the Commission has been notably reluctant to extend its jurisdiction over a larger, uncovered

sector of the wholesale transmission industry. The Federal Power Commission found in the Dairyland Power Cooperative 67 PUR 3d 348 (1967) that it had no jurisdiction over Rural Electrification Administration cooperatives. The Commission held the same in City of Paris, Kentucky vs. Kentucky Utility Company, 41 F.P.C. 45 (1969), with respect to an interconnection between two companies, one of which was a municipal company. Originally, the Commission held that it could not order Kentucky Utility to transmit power for the City of Paris Utility because the supplier and Paris were government "instrumentalities" and the F.P.C. had no jurisdiction under Section 201(f). The United States Court reversed on this jurisdictional issue in City of Paris, Kentucky vs. Kentucky Utility 399 F2d 983 (1968), with the Court majority stating that it would be in the public interest for the F.P.C. to have jurisdiction and the Court minority elaborating on this by stating that the need for development of a national power grid and coordination of the present systems were so important as to override the "historical intent" of the Congress. Even then, the Commission's response was very mild: on remand, the Federal Power Commission said that, although it could order Kentucky to transmit power to Paris from another producer, it felt that voluntary agreement leading to interconnection between the two utilities was a better solution.

In a number of cases, the Commission dealt directly with planning for larger systems and with coordination of companies. After the Consolidated Edison Company decision (354 F2d 608, 1965) in which the Commission was admonished for narrowly defining its role in determining service quality and its effect on the environment, the Commission has gone into detail on the alternatives to those specific plans being submitted for initial certification. The detail does not seem to have been excessive; in many cases, in fact, the Federal Power Commission appears to have fallen short of consideration of all the economic and social aspects discussed by parties to the action and of future ramification on the industry and environment. Frequently, the Commission has accepted a settlement among disputing parties that falls short of a solution to a problem, merely in order to provide immediate disposition of the case. In Public Utility District #1 of Snohomish County and City of Everett, Washington, 43 F.P.C. 656 (1970), the parties resolved the conflict between the need for adequate water releases to maintain the fish life in the river and the need for water and for more electricity by the local industry in the county. The Examiner's decision sketched out possible long range solutions to the entire set of environmental and industrial problems, through a program of regional development of the river; but the Commission felt that development was a "local issue" and they should accept the local determination

of the problem, so that they put no conditions on their approval and gave no advice. In Crisp County Power Commission vs. Georgia Power Company, 42 F.P.C. 1179 (1969), the Commission approved a settlement on an interconnection order, after a refusal to deal, that ignored its own tentative opinion (67 PUR 3d 75, 1966) where it gave what it thought should be the fair charges and arrangement, and it also ignored the Examiner's preliminary decision on the same issues. This was justified on the grounds that "immediate relief" was available, without having to review the whole situation to determine a more elaborate (perhaps more efficient) solution. At times, the Commission has also ignored considerations clearly of central concern in planning processes. In Rocky Mountain Power Company, 67 PUR 3d 437 (1967), the Commission dismissed an application for a power project because the applicant had no firm power sales contracts -- this in the face of testimony from the Nebraska Utility Commission that stated that there would be a power shortage in the area in the near future. The application was dismissed without prejudice, to allow reapplication when a need could be shown through the existence of unfilled sales contracts, and the United States Court upheld this action because of the clear opportunity to reopen the application (at 409 F2d 1122, 1969). However, one Commissioner's dissent in the F.P.C. decision made it clear that the Commission could have gone on to the

merits of the particular plan since it was before the Commission, and that to have done so would have clearly been part of its planning function and its legal duty to provide for comprehensive development of the waterways.

The Federal Power Commission has taken a similarly tentative and conciliatory approach to the need for cooperation and coordination, in a series of cases concerning refusals of production companies to deal with retail distributors. The issue has been whether the refusal of a production and transmission company to "wheel" power from another production source to a particular retail distributor within its region would violate any of the widely-defined "quality of service" requirements of regulation. As part of its response, the F.P.C. has stressed the mutual benefits that arise from interconnections and the reliability added by pooling arrangements. However, even in this area, the F.P.C. has had a limited view, preferring to have the companies in the controversy work out a program of direct service rather than having power wheeled in from an indirect production source. In the City of Paris case, the Commission worked out a voluntary interconnection between adjoining companies rather than having the power wheeled from outside the Kentucky Utilities area. The Commission went on to state that requirements to wheel were not going to be imposed, but rather that wheeling was to be voluntary.

In a series of further decisions, most of which were concerned with the development of the Northfield Project in Massachusetts, the Commission shows this narrow view on requirements for coordination. In the first decision, the F.P.C. granted a license for construction of the project and dealt with the question of rating of the transmission lines. The local municipally-owned distribution companies stated that a 500 kilovolt line would be preferred because it could become a segment of a New England-New York-Canadian regional grid, while lines smaller than that would be insufficient to contribute to this larger regional system. The promoters of the Northfield Project preferred a 345 kilovolt line, and the Commission agreed, citing a study showing that this would be cheaper at the level of projected capacity use (that is, if there were no regional interconnection and no weight were given any gains from future systems coordination). In this case, Western Massachusetts Electric Company 75 PUR 3d 1 (1968), it was stated by the Commission that: "while the studies are not as broadly conceived as desirable, there is still enough to show that the project is economically feasible," hardly a comprehensive assessment of a component of a regional pooling project.

In further hearings scheduled for assessment of the total capacity of the project, the Commission again approved transmission

capacity that was limited in scope to single company operation, stating that issues of a comprehensive plan for regional power development need not be raised with each application for a single company's project. The United States Court upheld this position in Western Massachusetts Electric Company 414 F2d 1200 (1969), stating that the Federal Power Commission is not responsible for the development of the best overall power system, but merely for the best development of the specific waterway involved in the application for a water power project alone.

As a result of this melange of orders and cases, a singular and consistent viewpoint of the Federal Power Commission's role in comprehensive power planning is extremely difficult to formulate. It does appear that the Commission has sought to bring as much as possible of the water power capacity in the country under its jurisdiction, but that in general it has allowed the individual companies to work out their own coordination arrangements when it comes to using this capacity along with the fossil fueled steam electric capacity in a coordinated system. To the contrary, in some cases the Commission has dealt directly with coordination; in the cases on "refusals to deal," the Commission has acted as if to protect small municipalities from larger private interests -- saving them through interconnection orders -- where this was probably counter to the gains from systems coordination. Yet other decisions seem to have abandoned

the municipalities for protection of the interest of the large private producing companies (as in the Western Massachusetts Electric cases). Thus, it is difficult to see this as a wholly consistent program of invoking a policy either towards coordination or towards company pluralism.

The most insightful interpretation may be the Commission's own. In testimony before the Senate Commerce Subcommittee on Energy, Natural Resources and the Environment in January 1970, the Chairman of the Federal Power Commission, John Nassikas, put the question: "What operating and utility regulatory procedures are most likely to ensure the timely installation of needed electric and gas utility facilities and the operation of all systems on a progressively more reliable basis...?"[29] The answer given by the Chairman was company procedures to strengthen company and governmental coordination, "without creating in the F.P.C. a new set of certification procedures controlling generating plants and transmission lines."[30] This is because "regulatory mechanisms, if they are to retain their historic independence from the economic interests which they restrain, should not impose the planning duty upon the regulator..." so

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[29] Statement of John M. Nassikas, Chairman, The Federal Power Commission, Hearings before the Subcommittee on Energy, Natural Resources and the Environment of the Committee on Commerce, U.S. Senate, January 30, 1970, p. 7.

[30] Statement of John M. Nassikas, op. cit., p. 43.

that "reliability objectives can be attained by coordinated state action, regional reliability council work and industry action under policies coordinated by the F.P.C."[31] With the overall F.P.C. approach being that of fostering "voluntary coordination," then the case decisions would not break new ground towards far-reaching coordination or systems pooling. The Chairman himself states that "the Commission has not sought to test the limits of its compulsory regulatory jurisdiction as it relates to reliability and adequacy of service. ... The authority of Section 202 (on required interconnection) is invoked by a complainant utility system."[32]

What have been the results of this approach by the regulatory authorities? In fact, systems coordination has proceeded rather slowly and has not extended the individual planning unit.

The standards laid down by the National Power Survey in 1964 called for a minimum of twenty planning units in the country, and at the ideal four or less planning units, for construction and operation of safety margin and reserve capacity in electric power. If regional planning entities were to have an effect upon the size of total new additions to capacity,

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[31] Statement of John M.Nassikas, op. cit., p. 44.

[32] Statement of John M. Nassikas, op. cit., p. .

so as to bring about the savings from coordination shown by the _Power Survey_ for 1980 and thereafter, then there should be no more than twenty such entities responsible for construction projects initiated in the early 1970's. There are far more than twenty now extant; there are twenty-two power pools now in formal operation, but -- even if they have the capacity to make decisions for individual producing companies, which many do not -- they account for only 60 percent of the country's generating capacity.[33] The pooling organizations have to be expanded in scope to cover half again as much capacity, in order to be in the position to plan twenty coordinated systems for 1980.

The coordination that saves on capital in particular has been extremely limited. Most of the "power pooling" has not incorporated companies across time zones, or companies in different parts of the country with different scale and vintage of equipment, but rather has formally enfolded adjoining small generation and transmission companies to the largest producing entity in that particular region. The additional coverage by the twenty largest producing entities, after organizing to become the twenty largest power pools, has been small as a consequence. In 1964, the year of publication of the _National_

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[33] Testimony of David S. Schwartz, _op_. _cit_., p. 597.

Power Survey, the twenty largest producing firms or power authorities accounted for approximately 50 percent of national production capacity.[34] The last seven years have brought forth a gain from coordination of ten percentage points of national capacity under the control of the largest twenty entities, at the most.

This small gain can be said to have been achieved by voluntary pooling, if the resulting pooling operations have control of the aggregate capacity of the companies included in the pool. This is not at all certain. Some pooling organizations bear all the earmarks of disjointed federalism in the relations between companies that are members of the organization, while a very few other organizations are marked by strong central planning and operations. At the worst, there have been no real gains in coordination, given that the major systems in high-density areas were interconnected ten years before the National Power Survey (the Interconnected Systems Group--ISG--

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[34] According to the Federal Power Commission's Statistics of Electric Utilities Privately Owned and Statistics of Electric Utilities Publicly Owned. For 1964, the twenty largest electric power systems accounted for 49.6 percent of capacity. This excludes the capacity of the 5 largest hydroelectric power agencies: The Power Authority of the State of New York, The Bureau of Reclamation, The Bonneville Power Authority, Southeastern Power Administration, and Southwestern Power Administration. They are excluded on the grounds that the size and extent of coordination in these agencies is primarily a decision of the Federal Government and the availability of hydroelectric resources. If they were to be included, however, the largest twenty companies, including these five "companies", would have 46.9 percent of total capacity.

included most of the major systems in the midwest and southern parts of the country by the middle 1950's, even though the extent of interconnection was so limited that regional decisions on operations were impossible). At best, the voluntary policy for twenty national pooling systems has proceeded one-fifth of the way towards its final goal in the years since 1964.[35]

With such limited results, it would not be unreasonable to conclude that the Federal Power Commission's "voluntarism" has had no significant effect on area planning and coordination across electric generating companies. The economic costs of safety margins and peaking capacity are as great today as they were in the middle 1960's, except for the small gains from the gradual drift of adjoining companies into cooperative organizations in their own respective sales areas. There may be two exceptions: coordination in the transmission of natural gas may have been furthered by Commission activities, and a few of the large number of F.P.C.-approved mergers among power companies may lead to cost savings in the next decade.

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[35] That is, starting from a base of 50 percent of capacity in the twenty largest non-pooled systems, pooling has succeeded in setting up 20 entities with 60 percent of capacity -- an addition of one-fifth of the uncoordinated 50 percent of capacity.

Coordination among natural gas pipeline companies in fact has proceeded at an imperceptible rate in the last decade. The search for sources of new field reserve supplies by individual pipelines has been intensified by widespread excess demand, and this has dominated any tendency towards sharing of facilities and pooling of resources. If two pipelines were to consider the trading of reserves or the "exchange" of transmission "space" to form a shorter combination of lines, then there would have to be agreement beforehand that there were sufficient reserves for the established customers of both lines. The sufficiency of reserves has been the issue, of course, and has led to competitive projects by pipelines, or competitive offers of exceptional contract conditions by one line over the other, rather than to movements towards reducing overlapping capacity or reducing the "round-about" transmission of gas.

There is no conceivable role to be played by the Commission in movements towards increasing the "quality and quantity of gas service" under these circumstances. Policy problems on planning are quickly lost in the confusion of excess demand, both at the Commission and in the companies. The Commission has the urgent and prior task of restructuring the exchange contracts so as to relieve excess demand (as shown in Chapter 2).

The Federal Power Commission, regardless of priorities, has played some role in setting a pattern for rationalizing

construction of overlapping pipeline extensions in the offshore Louisiana area. A number of pipelines had made applications to extend facilities into the same offshore producing region, and the Commission responded with a statement of policy in June of 1968 (Order #363) which called for considering these applications jointly, in order to prevent undue and costly overlapping of the extensions. The response of the pipeline companies has been to announce a number of joint ventures where previously single company proposals had been made; while these have eliminated some duplication, the staff opinion at the Federal Power Commission still is that "collectively ... (the joint ventures) disclosed apparent duplication of facilities, crosshaul, low utilization of factors and excess capacity."[36] The Federal Power Commission itself has not made this finding, but rather has been dealing with the proposed ventures one by one in case decisions on certification.

The decisions, while preliminary or incomplete at the present time, will very likely lead to the elimination of more duplication. The Commission has raised the issue in its statement of policy, and has proceeded to question whether it has been resolved to a significant extent. The Commission has also

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[36] Statement of L. A. Brubaker, Jr., The Federal Power Commission, September 24, 1968, as quoted in the Testimony of David S. Schwartz, op. cit., p. 583.

provided the impetus for quantitative models of offshore pipelines as a system, by sponsoring a report of the Office of Emergency Planning on Design of Economical Offshore Natural Gas Pipeline Systems (Report R-1, National Resource Analysis Center, Systems Evaluation Division, October 1, 1968). This again is preliminary since it provides an initial description of the "network analysis technique" and then offers a specific proposed offshore system which would provide 30 percent additional capacity at a saving of approximately $7 million (of $300 million in initial construction costs), both of which are first steps towards systems optimization. But, even though preliminary, the Commission has formulated a policy beyond "voluntarism," and has begun to put this into effect by means of case decisions on Certificates of Necessity and Convenience. This may eventually result in more coordination in the construction and operation of gas transmission lines.

The merger policy of the Federal Power Commission can be found in part from analysis of case materials. The Commission has had the authority to prevent the sale, lease, or disposition of electric power facilities "subject to the jurisdiction of the Commission" under Section 203 of the Federal Power Act and to regulate the mergers of natural gas companies under Section 7c of the Natural Gas Act. In the middle 1960's, the scope of the

authority of the Commission was established by a decision with respect to the Duke Power Company (36 F.P.C. 399, 1966), on appeal to the District of Columbia Circuit Court, where it was stated that the F.P.C. cannot require approval of the merger of an interstate utility with a company having facilities used exclusively for the intrastate distribution of electricity.[37]

Beyond issues of jurisdiction, the rules governing mergers are unclear. There have been close to 100 merger cases in the last decade, along with 60 to 70 partial acquisitions requiring case decisions; they involved such a wide variety of considerations that a clear statement of "what the Commission has been doing and proposes to do" with respect to consolidations is very difficult to make.[38]

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[37] Duke Power Company vs. Federal Power Commission, 401 F2d 930 (D.C. Circuit, 1968).

[38] The mergers involved companies of widely varying function. Seven mergers involved simply a change of corporate domicile -- the transfer of assets from a company in one location to the very same owners through the form of a company in another location. There were consolidations of wholly owned subsidiaries as well. Others were the result of adjusting the ownership of an affiliate's facilities to operational responsibilities. There were mergers involving the acquisition of small utilities whose operating areas were surrounded by the area served by the larger merging company. Several mergers involved the acquisition of electric facilities owned by lumber companies, textile companies, or universities. There were purchases of a small town or city's own electric generating facilities, or leases of these facilities, to a larger electric system.

Without exception, every application for a merger has been approved by the Federal Power Commission. This has been as true of complete mergers involving relatively large utilities, as of trivial instances of merging to make changes in corporate domicile or to acquire short pipeline segments or electric transmission lines. Therefore, the significance of the continuous record of approvals lies not in the number of approvals, but in those involving the larger companies that result in consolidation of extensive facilities.

Here there would seem to have been no overriding standards for approval, at least not related to coordination efficiencies. In Northern Natural Gas Company (43 F.P.C. 228, 1970), the issue was the merging of six unconnected interstate systems of the Plateau Natural Gas Company into the Northern Natural Gas Company system. Here the Commission had the opportunity to point to gains from coordination, perhaps, but the order approving the merger contained no discussion of potential benefits or harm that the transaction might entail. In the earlier Southern California Edison Company and California Electric Power Company merger (30 F.P.C. 942, 1963), the Commission specifically pointed to benefits from being able to construct larger generating units, from adding to "the diversity of loads" and from the "elimination of duplicate service." These phrases are the same as in earlier cases, dating from the decision of the Circuit Court in Pacific

Power and Light Company vs. F.P.C. (111 F2d 1014, 1940). The Court in this decision required that the applicant show to the Commission that the merger was "compatible with the public interest," and the Commission has interpreted this requirement to mean that there is no evidence to the contrary of general statements that in any merger "corporate structures will be simplified," "administrative economies will result," and "duplicate facilities will be eliminated." The Federal Power Commission makes these statements without positive elements of proof establishing them in specific cases -- they are assumed.

Most recently, the Commission's predilection to approve all mergers has resulted in three case disputes in which standards on prices and on systems coordination were brought into focus. In a case involving the merger of two Iowa utilities, the Attorney General of that state objected on grounds that, while the systems gains were negligible, the merger would result in a monopoly of electricity supply in that state.[39] In the extensive and prolonged case of United States vs. El Paso Natural Gas Company (376 U.S. 651, 1964 et seq.), the first point of issue was the Federal Power Commission's attempt to immunize the merger of the El Paso Natural Gas Company with the Pacific Northwest Pipeline Company. The Antitrust Division of the Department of

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[39] Cf. Opinion #590, Iowa Power and Light Company, Docket #E-7494 (December 24, 1970).

Justice filed suit to prevent this merger, and the El Paso Company's reaction was to apply for and receive the approval of the Federal Power Commission, on the usual grounds that the applicant need not show positive benefits to the economy but merely the absence of negative effects from the merger. The Supreme Court on appeal ruled that the Commission has to treat evidence of antitrust violations in merger applications, and cannot grant antitrust immunity for these mergers. In the Great Lakes case, involving a proposed joint venture by two potentially competitive pipelines to transport Canadian natural gas through the Great Lakes region, the Commission was ordered to hear antitrust evidence and weigh it along with other factors making up the "public interest standard." In this case, the Commission, rather than comparing adverse antitrust effects with positive coordination benefits, evaluated the antitrust effects alone and found them not to be "serious," so that it reaffirmed its initial approval of the joint venture.[40]

The three cases together indicate rather lenient standards for decision-making on mergers. The Commissioners accept an application of adjoining companies for a merger as being beneficial on its face, and then seem to require antitrust-oriented intervenors from the staff or Justice Department to bear the

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[40] Opinion #580, Great Lakes Transmission Company, Docket #CP 66-110 (July 10, 1970).

burden of proving significant negative effects. The standards do allow mergers to take place that increase the quantity and quality, and reduce the cost, of electric and natural gas service. But these standards support mergers which do the opposite as well, since they are not directed towards increased efficiency. In practice, the allowed mergers would seem to add to the tendency of adjoining companies to consolidate or coordinate their activities, without entering into regional or subnational coordination designed to greatly reduce capital expenditures and systems outages.

Federal Power Commission actions on environmental quality have been few in number and relatively unimportant -- when the opportunity has been great. The quality of energy has clearly been found to have important aspects of environmental quality at the locations where Federal Power Commission regulated companies are found. One result of increased concern for quality has been the burgeoning growth of state and local agencies regulating the construction and operation of F.P.C.-regulated electricity and gas companies. The construction of new plants has been delayed and in some cases relocated or prevented entirely, and the Commission has duly monitored these increased delays. Another aspect of the increased environmental concern has been increased criticism and public action against the Commission itself for certification of new facilities on the

basis of narrow or industry-oriented standards. The Commission has reacted to this concern, when faced with requirements by the Federal Courts to open up cases to broader quality or environmental considerations.

But has the Federal Power Commission developed policies on environmental quality? In the licensing of electric power projects, the F.P.C. has at times placed conditions on the license different from those sought by the applicant. The Commissioners have not in the last few years denied applicants, but in some cases have given them licenses for slightly different projects where the "expanded" projects included new aesthetic or recreational conditions. In the Pacific Gas and Electric Project #2467, the company applied for a major license to operate a project on the Merced River, and there were responses from a number of Federal and state agencies seeking to attach requirements for recreation. Because the project was long since complete, there were no recommendations for revising construction plans, but the United States Army Corps of Engineers recommended that minimum stream flow standards be imposed as license requirements, and these were required by the Commission in such vague terms as "the licensee shall operate the project in a manner to prevent rapid and extreme fluctuations in the reservoir level ... and coordinate project operations in the

interest of fish and wildlife."[41] In the case of Georgia Power Company's application for the Lauren Shoals Project, the dam and turbine facilities had not been built and the conditions requested by the Department of the Interior were more stringent. The Commissioners took under advisement the extensive recreational use plan proposed by the Department, and an exceedingly narrow plan proposed by Georgia Power Company, and split the difference -- after stating that in principle the "responsibility for acquiring and developing lands for recreation areas rests on the applicant" but this had to be subject to the applicant's "financial ability to construct and operate the project."[42] In the Consumer Power Company application for a license to construct a pumped storage facility, Federal conservation agencies requested even more extensive facilities for recreation, and the Commissioners required even less, than in the Georgia Power Company decision. The companies' responses to the Department of the Interior's demands for landscaping of a ridgeline of the power project was that this would "necessitate the addition of millions of yards of fill material to the dike, increasing the cost in the neighborhood of $10 million."[43] The view of the Federal Power Commission was that

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[41] 42 F.P.C. 237, at 238.

[42] 42 F.P.C. 356, at 359 and 362.

[43] 42 F.P.C. 274, at 275.

the cost of this redesign was obviously very extensive, so that they rejected Interior's proposals and allowed the license without any requirements for environmental improvement.

The three cases together indicate that the requirements to do with the "environment" are certainly not extensive. At least these decisions did not abridge the ability of the company to build anything that seemed profitable, and when there was some chance that the expenditures to meet the requirements would exceed 10 percent of the project budget, then they were excluded in the final decision. The Federal Power Commission has centered its attention on the profitability of large scale power projects, subject to some small proportion of the profits being used to provide recreational services for the communities close to the projects. There has been no interest expressed in these decisions in determining whether the costs of recreation ought to be imposed on the industrial and home consumers of electric power. Recreation has been itself the only matter of concern in "the environment," with little or no attention being paid to pollution, congestion or other "external diseconomies" created by the project and imposed on neighboring communities. All that can be concluded is that the Commission does consider some aspects of the environment -- the recreational aspects -- in a consistent fashion in certification of new hydro-power projects.

The Federal Power Commission has gone a great deal further, in principle at least, with two recent administrative statements of general policy, one concerning environmental and aesthetic conditions in the exercise of hydroelectric licensing authority (in "Protection and Enhancement of Natural, Historic and Scenic Values in the Design, Location, Construction and Operation of Project Works," Docket #R-365), and the other setting environmental standards for certification of new pipeline facilities under the Natural Gas Act (selection, clearance and maintenance of rights of way routes in construction ... by natural gas companies, Docket #R-360). These set guidelines to be followed by electricity and gas companies in constructing new facilities -- guidelines for preserving "scenic, historic and recreational values" -- that appear to be stringent. For example, they range from a requirement that "soil which has been excavated during construction and not used should be evenly filled back onto the clear area and removed from sight...." to the requirement of documents showing what is being done to prevent "damage to the environment and to preserve and enhance the project's scenic values." As these new administrative standards are put into effect, the size of submissions in certificate applications will increase, and the number of days and weeks of testimony will be greater. The results remain to be seen.

The question is whether these new "guidelines" will result in additional substantive requirements imposed on companies seeking certificates -- whether, in the extreme, there might actually be a Commission denial of a certificate application in the future. The answer depends on how seriously the Federal Power Commission takes the larger view of regulation as a planning function for the economy as a whole.

At the present time, it cannot be expected that the Commission will play this role. The viewpoint of the Chairman of the Commission has been that planning for systems efficiency or environmental quality calls for "strengthening integovernmental coordination ... without creating in the F.P.C. a new set of Federal certification procedures controlling generating plants and transmission lines...."[44] Moreover, the Commission has not moved vigorously into environmental control activities. They have set up a "Task Force on Environment" to counsel the Commission on studies of environmental aspects, and have themselves undertaken studies on the aesthetics of power facilities and on the problems of disposal of waste heat from steam electric plants. The Commission has issued a report on air pollution from the regulated electric power and natural gas industries. Various members of its staff have served on intergovernmental committees

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[44] Statement of John M. Nassikas, op. cit., p. 43.

on power plant siting problems, on outdoor recreation, on natural beauty, and so on. They have provided their approval of trade association activities relating to the environment,[45] and a number of members of the Commission have made public statements, speeches, and given Congressional testimony on the importance of regulatory requirements in the environmental field. But they have not initiated rulemaking cases, nor have they reexamined pending cases on the basis of new standards for protecting the environment against the cost of construction of new power and gas facilities. The actual day-to-day Commission activities point to the use of administrative procedures, committees, and public forums, rather than to the application of the regulatory powers to control production. Not very much has been done towards putting controls into effect against degradation of environmental quality related to the energy industries.

An Overall Evaluation of the Commission and Systems Planning

There are two viewpoints from which to look at the behavior of the Commission and the electricity and gas companies. One is the retrospective view, gained from studying the recent history

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[45] Cf. Statement of John M. Nassikas, *op. cit.*, footnote on p. , *supra*.

of opportunities for comprehensive planning of the development of new technology, capital acquisition, and production. The second is prospective, and is gained by looking ahead to potential new developments in technology and demand, as well as by evaluating the present position of the regulators and regulated companies on abilities to respond to these changes.

From the historical point of view, there would seem to have been a number of important opportunities for economic and social gains from decision-making at the *industry* rather than the *company* level in electricity generation. Important industry-wide studies in the middle 1960's (including the F.P.C.'s *National Power Survey*) established that the gains from coordination in capital investment and operation of equipment could be in the billions of dollars per annum. There would have been gains, as well, from an industry-wide research and development program centered on capital equipment to replace increasingly scarce fuel, air and water resources. More speculatively, there might have been gains from more rapid application of area-wide planning so as to have prevented increased air and water pollution loads, or the delays consequent from multiple hearings, Court injunctions, and other reactions of local citizens and conservation groups.

These gains, to the extent that they have been realized, have been made without the active leadership or control of the

Federal Power Commission. The Commission would have been the logical source of initiative, because it operates at the industry level so as to control the actions and interactions of the separate electric generating companies. But the Commission has followed policies of "voluntarism" whereby they _permit_ the consolidation of adjoining organizations, or the formation of local power pools, but will not _require_ the setting up of any organization of specific membership beyond the individual firm level. The Commission has played no role in the development of new technology, nor has it used consistent policies in the last decade for protecting and increasing the quality of the environment in electric power generation. The planning function has been strictly a matter between companies.

This state of affairs is essentially present in the natural gas transmission industry as well. The problems of company coordination, to the extent that they exist, have been dominated by the shortage of natural gas field supplies. Companies have failed to develop systematic coordination in the joint utilization of capacity -- so as to shorten the distance from field reserves to final consuming points, for example -- because there has not been sufficient field gas available to meet all their demands. In the absence of sufficient reserves and production, and an unequal distribution of the amounts available as a result of historical circumstance, companies have

not been diligent in making transfer agreements. The Federal Power Commission has attempted to carry out first round experiments in coordination of construction of offshore pipelines; this activity indicates more leadership on their part than in any other area of planning. But it is of little importance, and will not provide a source of initiative, until the regulation-induced shortage of gas is ameliorated.

The prospective view is very uncertain. There are opportunities still for the development of economies of regional scale in the construction of capital equipment, for safety margin and peak load utilization in electricity. There are potential great gains from a national research and development policy for energy-using and energy transmission equipment. But is the Federal Power Commission going to be the source of initiative on these large scale and critical ventures? Here the answer can only be speculative but, when derived from the previous history of the Commission, it cannot likely be positive. The Commissioners have shown no predilection or ability to require companies to conform to a regional or area-wide program of construction or operation; rather, the Commission here, as in the case of profit regulation, has reacted to the proposals of the individual companies themselves. Without a change in approach to the industry as a whole, the Federal Power Commission will not affect the quality and total quantity of service provided by electricity and natural gas companies.

5. The "Necessity and Convenience" of the Federal Power Commission

The Federal Power Commission, well established in "middle age" of the lifetime of the independent agency, has developed a distinct record of regulatory accomplishments. The record shows an ability to initiate strong programs for protection of the consumer and enhancement of the quality of service offered by electricity and gas companies. When these programs go into effect over long periods, however, the collegial form of decision making has produced some perverse but mostly insignificant results. The case-by-case approach has not delivered on the initial promises.

The question now is whether alternative approaches could be devised that would increase the productivity of the Commission. The structure of the electricity and gas transmission industries, and recent performance failures such as shortages and service interruptions, demonstrate the need for comprehensive planning and reform in this level of the energy industries. There is need for reductions in prices for these services, as well, given that F.P.C. profit regulation "limits" profitability to twice the economic cost of capital in a year characterized by full employment and strong price inflation. Basic changes in the structure of the Federal Power Commission might be to new

Commission activities that could both restructure the transmission industries and reduce prices to competitive levels.

This question is examined in the paragraphs below, and some tentative answers are provided. First, the "record" of the Commission is reviewed, in terms of the findings in previous chapters as they relate to the structure of the regulatory agency. Second, proposals for reform of the planning mechanism in the industries, and of price controls, are presented. These are evaluated in terms of the "economic efficiency" standards used in the previous chapters. Last of all, requirements are stated for achieving these reforms in Congress and the Commission.

The Benefits and Costs from Regulation

The Federal Power Commission completes many tasks in a single day, from "certifying" a number of pipeline or transmission expansion plans to completing an investigation of an electric power blackout. Part of the day's work cannot be assessed in money terms, least of all in terms of "payments" for services rendered by an independent regulatory commission. But, at some stage of its activities, the Federal Power Commission has to be able to measure the value of its activities against two standards -- the flexibility and efficiency of market mechanisms without regulation, and the efficiency of alternative forms of governmental control. The Commission is in the business

of providing a service which has costs for the taxpayer in government expenditures and costs for the regulated firm in litigation, delay and other resource expenditures. The service brings about income transfers, and consumers' or producers' "surplus", that is measurable in dollar terms.

The consumers of electricity and gas, in whose name regulation operates, ultimately bear most of the costs of regulation. The major part of the costs turn out to be expenses incurred in litigation that become part of the "costs of service" for setting rates on electricity and natural gas. The minor part of the costs are the Commission's own expenses, which are reimbursed by tax payments from all government revenue sources. Together, they come to approximately $56 million in a typical year of regulation -- although they may vary from $45 million to $98 million per annum.

The consumers' gains, on the whole, have been startlingly insignificant. Table 14 is an attempt to assess these gains or benefits, in quantitative and qualitative terms, wherever possible. Electric power price regulation has produced "direct benefits" in the form of Commission mandated or approved price reductions in a typical regulatory year of an amount similar to the costs of regulation that year. In the long run, the "indirect" benefits cannot be expected to be greater, because the technical problems in allocating joint costs, sharing regulation with state commissions, and taking responsibility for only a minor portion

Table 14: Assessment of Benefits and Costs

Activity	Costs of Regulation [M=millions of dollars]		Benefits from Regulation for Consumers	
	Estimate	Range	Direct	Indirect or long term benefits
Electric Power Price Regulation	3M	2M to 5M	3M	Insignificant
Electric Power Systems Regulation	3M	3M to 4M	Insignificant	Insignificant
Gas Field Price Regulation	43M	33M to 81M	Negative	Negative
Gas Pipeline Profit Regulation	6M	6M to 7M	8M	Insignificant (positive)
Gas Pipeline Systems Regulation			Insignificant	Insignificant
General Commission Administration	1M	----	----	----
Total Annual Costs and Benefits	56M	45M to 98M		

of the generation and transmission service in a region, prevents the operation of effective regulation. Gas field price regulation, accounting for more than half the costs, produced wholly negative benefits for consumers in both a typical regulatory year and over a longer period. The setting of ceiling prices has so reduced consumption for those responsible for one-half of total demand that their losses must be greater than any gains from price reduction for the consumers in the other hald of demand. There are no net benefits from a single year's regulatory

activities, nor from the mere existence of field price regulation (as shown in Chapter 2). Gas pipeline profit regulation shares with electricity price regulation the pattern of low level litigation expenses and imperceptible results. One year's price reductions, from controlling changes in newly submitted price schedules, can produce benefits slightly greater than estimated costs of regulation but over a longer period prices on regulated pipeline sales to gas utilities have not been significantly different from those on unregulated industrial sales (after accounting for market and competitive conditions, as in Chapter 3). If there were long term benefits, they must have been of the sort that followed from selected price reductions, and from being able to control markets under regulation so as to discriminate more selectively in price; these possibilities would result in insignificant but positive benefits for the consumers.

The gains from systems regulation have been altogether insignificant in dollar terms. Some amount more than $9 million per year have been spent on planning and case decisions on safety, reliability and environmental effects from electricity and gas transmission services. There have been no measurable benefits for the consumers from these activities -- even though the Commission itself in the National Power Survey showed billions of dollars of annual gains from regulated systems coordination and planning.

These findings are not altogether surprising, when associated with a Commission long accustomed to deciding hundreds of cases each week by consensus among the members. Patterns of response to requests from regulated firms have been developed, which clearly reduce the number of cases, and also reduce the complexity and time length of those cases that cannot be avoided (in particular, the certification and licensing cases required by statute). The results have to be insignificant from the point of view of the consumers because they neither initiate nor rebut cases; initiation of cases by others in the name of the consumer could well have significant and beneficial results, but only after prolonged and controversial proceedings, and after the initiation of numerous follow-on cases to ameliorate these results. To the contrary, the Commission's activities may well have benefited those being regulated rather than final consumers of electricity and gas. The Federal Power Commission could be said to have been "captured by the public utilities" if an assessment of benefits and costs (like that in Table 14) for pipelines and electric power companies showed strong positive net benefits. The costs in such an assessment would be considerably less than those shown for consumers, since most of the costs of regulation are passed on as production costs to final buyers in the prices these buyers pay.[1] The direct benefits from regulation

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[1] To be sure, increased costs of litigation imply increased prices, and consequently reduced quantities demanded. The reduced quantities sold in many cases will show reduced profits over the long run. In a sense, increased costs of litigation

must have been negative, however, and of roughly the order of magnitude of the positive benefits shown for the consumers. Price reductions imposed on them by the Commission would have imposed these losses on the companies, if the regulated firms had seriously attempted to make and hold prices at the levels proposed to the Commission. The long run benefits of regulation would seem to have been to the contrary. Electric power and gas pipeline price regulation were of no significance, when measured against the unregulated levels of price in comparable markets or when measured against the small scale of the regulated service. The short run-long run differences may well imply that, although the Commission can take "credit" for reducing profitability of regulated firms in a particular regulatory year, the much more important forces of competition, entry, and changes in demands and costs of gas and electricity, render the Commission's activities indeterminate.

This is to suggest that the Commission is not "owned" by the firms that it regulates, in any economic sense of the word. To be sure, the early years of gas field price regulation would seem to have greatly favored a small number of established

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[1] (cont'd) are substituted for increased capital costs or increased sales with fixed capital costs, both of which can produce more profits under regulation. But these effects are of second order of importance since regulation costs are of such small magnitude compared to production, transmission, and distribution costs for electricity and gas companies.

East Coast pipelines -- since they held large amounts of reserves at low prices, price increases would have reduced their profits while shortages would not have had any effect on them; decisions in favor of maintaining old prices substantially increased the profitability of their operations. Also, the established pipelines have been greatly favored with certification of all of their expansion activities, with certification of proposed mergers, and with an absence of systems planning that would reduce the overlap and lack of coordination of lines' activities for the benefits of the consumer. But these again must be included in "insignificant effects" -- prices have not been set so as to produce greater profits on regulated than unregulated sales, and markets have not been divided so as to establish market sharing.

Certainly, the natural gas producers have not captured the Federal Power Commission. Of all the groups of "interested parties" within the purview of regulation, the oil and gas producing companies have fared worst. They have borne more than half the costs of regulation on the first round -- to be passed on to consumers in higher prices on the second round -- and were required to charge prices lower than the marginal costs of the market clearing supply of new reserves. In the early years of field price regulation, this might have been explainable as a

resolution of a conflict between producers and pipelines in favor of the pipelines; in the later years, since no one benefited, this result is explainable only in terms of the inability of the Commission to respond in any other manner.

Thus the history of the Commission seems to show no significant positive results for anyone. This is not altogether surprising, and may not be different from findings on the history of most of the other regulatory commissions. This may even be endemic in this form of public enterprise: "the problem of [Commission] efficiency ... is a problem of the nature of the tasks which we have given the agencies. These tasks probably could not be performed well even in theory, and amid the practical realities of confused ends and ambiguous standards they are, through the fault of no one in particular, performed abominably."[2]

The Reform of the Commission

Under these conditions, there are two directions in which the Commission can move -- as opposed to maintaining the present circumstances and not moving at all. First, the Commission could take on a larger scale of activity with vigorous enforcement of

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[2] James Q. Wilson, "The Dead Hand of Regulation", The Public Interest (Autumn 1971), p. 49.

new statutory and Commission-ordered rules. This holds little promise, since it would involve a repetition of the well established pattern of initial vigor in new activities followed by "middle age decline" as the case rulings develop over a period of years. Second, activities could be separated from the Commission and re-established where they would be more effective. This more promising avenue involves both "planning reform" and "price control reform".

Planning reform requires the establishment of a center of initiative for planning the structure of the natural gas and electricity transmission industries, and the behavior of companies in these industries where this behavior involves "external economies" or "external diseconomies". The planning group should have powers to require the interconnection of facilities, so as to establish and maintain regional power grids across the larger generating and transmission companies. The gains from such activities are appreciable -- at least as much as those shown in the National Power Survey, and perhaps far greater gains from the positive environmental effects from reducing the rate of construction of new generating capacity. The planning group would have to have the power to construct and lease or operate facilities which private companies found uneconomic or impolitic, and which show positive net social benefits from reduced safety

margins or system outage. The planning group ought to have the established expertise to evaluate pricing policies designed to reduce the demands for safety margin and for peak load capacity -- including much more stringent peak load pricing to induce those more elastic demands to postpone or transfer consumption to non-peak periods.

This planning group does not now exist, as can very well be seen. Although implied by the National Power Survey, it has not been put together within the Federal Power Commission, nor is it likely to be inaugurated and operated successfully within an essentially legalistic or judicial atmosphere. The process of operation requires (1) analytical expertise able to detect and evaluate cost savings from coordination, and social cost savings from the elimination of duplicative expenditures or environmental degradation, (2) administrative procedures for issuing injunctions and requiring interconnection or relocation of facilities, (3) public exposure of these actions so as to make other companies aware of systems problems. The Federal Power Commission at present is not able to provide a frame of reference for these actions -- indeed, the present frame of reference would be stultifying for this kind of activity.

The planning group should be lodged in the Executive Office of the President, with a Presidential appointee to make

rapid and immediate decisions on intercompany coordination in the electricity and gas industries, and to make comprehensive plans for the growth and development of these industries. This is indirectly to support the Ash Council recommendations that the regulatory commissions be transferred to the executive office, but with substantial additional reasons and with different results.[3] The reasons are that changing the locus of these activities can only improve the quality of Commission performance, given the strictly formal procedures now used within the Commission to inhibit that performance. The results of the inhibition have been to render the Commission ineffective, and this need not happen within a new organization (unless by design). Even though, "the historical record provides ample reason to believe that agencies would probably continue to be legalistic and formal"[4], then in the planning process at least consensus would not have to be reached among Commissioners on issues that are not properly part of F.P.C. procedure. Most important, the transformation of "voluntary planning" within the Commission to effective control of activities over industry

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[3] Cf. President's Advisory Council on Executive Organization, A New Regulatory Framework: Report on Selected Independent Regulatory Agencies (U.S. Government Printing Office, Washington, D.C., 1971).

[4] Cf. R. G. Noll, Reforming Regulation: An Evaluation of the Ash Council Proposals (The Brookings Institution, 1971), p. 88.

growth and development would take place in a period of extreme concern for electricity and gas shortage or systems outage, so that the atmosphere would be conducive to the building of an effective organization.

Price control reform should be in the direction of "deregulation". There should be new statutory and Commission requirements for deregulation of natural gas field prices. The process has already begun, in the Commission's default on formal public utility price setting procedures in favor of "negotiated" prices in the reopening of the Louisiana Area Rate case. This movement should be accelerated to the decontrol of all prices in contracts for the commitment of new reserves and in gradual escalation of old prices. The old prices might be increased concurrent with tax increases imposed on producers so as to remove windfall profits on these old transactions; but they would still be necessary, in order to reduce the artificial levels of demand now found where there are prices below the market clearing level. The urgent necessity is to clear markets of demands that would not exist at higher prices but that are now being satisfied with gas not available to consumers willing to pay the higher prices. This can only be done by removing natural gas field price regulation entirely, as the history of Commission activity, and the economic

analysis of competitive markets, both indicate.

There ought to be deregulation of prices charged by electricity companies and gas pipelines, as well, but not for the same urgent reasons. These prices have not been controlled effectively and the control process has generated tens of millions of dollars of regulation costs each year; prices would not be affected by decontrol, but regulation costs would be much reduced, so the case for deregulation is "cost effective". The alternative case -- for more stringent regulation -- cannot be made, because there are no obvious mechanisms within Commission control for establishing and maintaining this more stringent regulation. The Commission as presently constituted would have to continue to react to initiatives of the regulated firms. Judicial procedures would tend to reduce controversy, and thus the stringency of procedures. Moreover, there are not well developed procedures for finding _a priori_ economic costs of capital, so that there are no simple or administratively operable ways of finding limits on prices before they are charged. As James Wilson has noted, "one of the ironies of economic regulation is that it has generally existed with respect to those tasks it can do only poorly (such as setting rates and prices and controlling market entry)."[5] With no known better way, the alternative

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[5] Cf. James Q. Wilson, _op_. _cit_., p. 58.

of deregulation is still "cost effective".

How far should profit deregulation go? This would seem to depend on the techniques most useful for establishing effective administrative controls. The replacement of Commission "judicial" action with administrative action is essential in order to establish some effect on the level of prices where they are regulated. The essential element in administrative action would be analytical expertise -- in comparison of prices across markets, where some sales are for industrial purposes, and a number of sales take place where there are more than two or three independent sources of supply. The expertise would be to establish general conditions for effectively competitive pricing, and to use these conditions as criteria for deregulation. Where effective competition exists -- where there are other "close" substitute sources of energy, and more than one pipeline is available to offer independent gas sales prices, or more than one electric generating company is able to offer independent capacity to an electricity retailer, then sales could be deregulated. Where these conditions did not exist, then "representative prices" from statistical regression analyses and comparative economic studies could be used to establish an upper bound on regulated prices. The form of the analyses might be similar to the study of regulated versus unregulated gas prices

in Chapter 3 -- but the form is not important; rather, the content would be essential, and this would consist of an economic analysis of competitive as compared to non-competitive prices where the competitive standard was derived from performance where there were substitute sources of energy and two, three, or four pipeline sources or electricity generation sources of supply. Profit regulation would be replaced with selected and specific price controls, where the level of price under control would be set by comparison with "effectively competitive" prices on the same per mile or per unit of output basis.

Planning reform and price regulation reform could very well be quite complementary. The establishment of efficient and widespread transmission systems in the electric power industry would provide the retail distributor with access to a much larger number of sources of supply of generating capacity than has been available in the past. The establishment of pipeline interconnection, so as to save on new construction and best utilize presently available facilities, would give retail gas utility companies access to more pipelines, and more sources of reserves, once the field price ceiling has been eliminated and the field supply shortage ameliorated. Effective planning would make the number of sources of supply far greater at the production

level, and the transportation system far more efficient at the distribution level. Both ought to reduce the need for regulation.

The need would still depend in good part on effective operation of transmission systems. Without stringent control of transmission charges, the effects of competitive pricing in electricity generation would be lost in excess or unduly high "wheeling" charges placed by the transmitter on the retail buyer. There may be no means any more effective for limiting charges over the national grid, or over the interconnected pipeline grid, than have been available in the last few years. If competition does not develop among pipelines and across sources of energy, so as to establish effective benchmarks for deregulated pricing, then the only economic alternative may be government operation of these transmission grids. This alternative cannot be said to be "cost effective" at the present time, since so little is known of government operation of energy transportation facilities in this country; the administrative organization, and the objectives of the organization, may be overwhelmingly important in establishing performance of a government enterprise in one or the other of these industries, and these have not been designed and ocnstructed as important parts of our political operation. But there has to be a national

power grid in the United States in the coming decade, and a national gas transmission grid, and there is little hope that these will evolve under existing patterns of ownership and regulatory control. The development requires regional power agencies or much more strict regional regulation of investor-owned utilities and gas transmission companies, and both public operation of the transmission business and much more incisive regulation should be investigated.

The public agency, or the incisive commission, could well confine operations to the transmission level of the industry alone. In these circumstances, the retail public utility whether publicly owned or regulated by state commissions would be able to buy in effectively competitive markets, purchasing either power producing capacity from a number of private sources located somewhere within one-quarter or one-half the country, or from sources of natural gas field supplies throughout the Southwest region of the country. These supplies would be transmitted either by the public agency, or by private companies operating on a "common carrier" basis with rates set either by competitive conditions or by much more strict governmental control.

The Practicalities of Reform

There are important questions of where the reform is to take place, and how it is to be carried out. The deregulation procedures could take place within the framework of the Commission itself, as a result of F.P.C. orders and case decisions. Alternatively, new legislation could be proposed and passed in the Congress which called for reorganization of Commission structure and the elimination of some of the F.P.C. programs.

The initial step in new policy, in our view, is accomplished by the Federal Power Commission simply ceasing to set producer prices. This might be done directly by the Commission, as a matter of rule making, or by Congress, which by legislation would remove producers from Commission jurisdiction. For the Commission to eliminate producer price regulation on its own has advantages and disadvantages. For one thing, the Commission could retain some control over producers upon whom special circumstances may bestow market power. These "standby" controls have advantages of giving the Commission access to price setting in such markets, and the disadvantage of maintaining an umbrella of regulation over prices on competitive transactions in other markets. Since the competitive transactions seem to predominate, the disadvantages of standby controls might be substantial.

The major obstacle to the Commission acting on its own initiative is the Courts. Would they hold that the Natural Gas Act required the Commission to regulate producer prices? There are reasons to believe that they would make such a decision. The major reason to fear Court reversal of unregulated pricing is that the Courts have consistently supported the Commission's efforts to control prices in the past. The initial Phillips decision held that the Commission had jurisdiction to regulate producer prices despite a Commission interpretation to the contrary. In the CATCO case[6], the Supreme Court reversed the Commission and held that it must not license producers to sell gas without conditioning the license on the producer's promise to charge a reasonable price. In Wisconsin versus Federal Power Commission[7] and in the Permian Basin Area Rate cases[8], the Court gave the Commission broad discretion to revise appropriate methods for controlling producer prices. There is no doubt but that the Court might hold that to allow market forces to determine producer prices would be to fail to regulate a "natural gas company" and is inconsistent with the statute's mandate.

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[6] Atlantic Refining Company v. Public Service Commission of New York, 360 U.S. 378 (1954).

[7] 373 U.S. 294 (1963).

[8] 390 U.S. 747 (1968).

There is a stronger probability, however, that the Court would not disturb the Commission's judgment. In our view, such a decision would be the better one, not only economically, but in legal reasoning. The Commission's judgment would rest on a determination that market forces were sufficient in the ordinary case to prevent producers from raising prices above competitive levels, so that they could be relied upon to set rates that were just and reasonable. The Commission could state that any attempt to interfere with market forces would do the consumer more harm than good. In the case of Federal Power Commission versus Hope Natural Gas[9], the Court stated that "the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate making function moreover involves the making of pragmatic adjustments ... and when the Commission's order is challenged in the Courts, the question is whether the order 'viewed in its entirety' meets the requirement of the Act.... Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling." The Court reiterated this sentiment in both Wisconsin versus Federal Power Commission and in the Permian Basin Area Rate cases. In fact, "it has been repeatedly stated that no single method need be followed by the Commission in considering the justness and reasonableness

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[9] 320 U.S. 591, 620.

of rates" (Wisconsin versus Federal Power Commission, 373 U.S. at 309). A Commission determination, based upon sufficient evidence that competition was ordinarily sufficient to maintain just and reasonable prices, would seem to meet the standard. Moreover, although it may be socially desirable to transfer rents from producers to consumers even where competition sets prices, nothing in the statute's legislative history suggests that such was the intent of Congress. The Commission would seem to fulfil its role in protecting consumers from the exercise of monopoly power, by analyzing market structure and general performance so as to establish that prices are set competitively. These competitive prices would be "just and reasonable".

Thus, suppose the Commission found after a hearing and after fifteen years of experience with different methods of regulation, (1) that competition could be relied upon to set just and reasonable producer rates in most instances, (2) that regulatory efforts to force some prices below the competitive level to transfer rents were unlikely to be successful, and (3) so that the F.P.C. would interfere with a market determined price only after a special showing that a producer, in unusual circumstances, possessed market power. Under ordinary principles of administrative law, the Courts ought not to interfere with

such a finding, for it complies with the basic Congressional purpose of the Natural Gas Act and substantial evidence can be mustered in support of its wisdom. The Court's prior opinions in the area suggest they would defer to the Commission's judgment. In a sense, the Commission would be in a stronger position than has been the National Labor Relations Board when it has declined to exercise its statutory jurisdiction over certain particular industries[10] or the Federal Trade Commission when it has refused to proceed against unfair labor practices. The NLRB's selective exercise of its jurisdiction in other agencies' use of "prosecutorial discretion" to decline to proceed in a particular case reflect an effort to reconcile limited administrative resources with a statutory policy favoring jurisdiction. A decision to "deregulate" producer prices would be a determination that casual and selective, rather than pervasive, interference with the market is the most appropriate way to regulate this portion of the natural gas industry. It is therefore not surprising that the Federal Court of Appeals for the Fifth Circuit, after stating that "the decisions of the Supreme Court definitely indicate the Commission has a responsibility to take the steps necessary to assure that wellhead prices are

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[10] See, for example, Labor Board v. Denver Building Council, 341 U.S. 675 at 684 (1951).

in the public interest. The Commission does not have to employ the area rate method or for that matter regulate prices directly at all, but it has chosen to fulfil its duty in that manner here."[11]

The alternative to Commission action is Congressional legislation. Congress might specifically remove the Commission's authority to regulate producer prices. Such a course of action has one major advantage: it may be possible to couple such a bill with other legislation that would maintain some of the income transfer benefits that producer regulation now provides. If producer prices were not regulated, it would no longer be as necessary to provide government subsidies to encourage producers to look for gas. Congress then might repeal the tax depletion allowances, which in effect provide such subsidies. It might be possible to couple the deregulation proposal, as well, with legislation that liberalized the present oil import quota system. Strong arguments have been advanced to show that the quota system unnecessarily raises consumers' fuel prices and gradually ought to be abolished.[12] As a consequence, tax increases on natural

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[11] Austral Oil Company v. Federal Power Commission, 428 F 2nd 407 (emphasis added).

[12] Cf. President's Task Force Report on Oil Import Quotas (1970).

gas and oil would be coupled with price reductions, so that the "income transfer" from producers to consumers would be carried out indirectly and without undue legal jurisdiction.

Despite these potential advantages, there should be second thoughts before advocating the passage of new legislation. To remove all jurisdiction might be marginally undesirable, for some form of regulation might still be useful because of exceptional market conditions at some locations or because market conditions might change over time. This is to appeal for "standby regulation" and is not a strong appeal, because of the potential misuse of such regulation.

The development of deregulation of pipeline and electricity company profits is a problem for the Commission, and, probably, for the Commission alone. This organization has the expertise with present cumbersome and inefficient methods and with new directives and guidelines from Congress, could use this experience to lay out effective new standards for price control. The directives from Congress would be necessary to delimit the jurisdiction of controls. The new standards would have to be proposed and then adjudicated through the Commission procedures of an examiner's review, a case decision, and a Court review on appeal. But the appeal would be to establish administrative procedures for comparing prices across markets, where some markets have many

sources of supply and some have very few sources of supply. The purpose would be to institute new procedures within the Commission that did not contain the essential elements of judicial review, because judicial review is expensive and time-consuming, there are no standards on which to review individual rate structures, and past experience has shown the ineffectiveness of the review procedure.

The approach in both field price regulation and pipeline or electricity regulation is to require the Federal Power Commission to reduce itself from present levels to no more than one-fifth of present scale. It is realistic to propose that they be required to do so, but also to propose that orthodox regulation of prices and profits still be carried on within the Commission form of organization.

The last question is whether this reform can actually be expected to take place. This is a political question and it deserves at least a partially economic answer. Reforms of this nature seldom take place, even if they are proposed rather frequently by economists and lawyers after completing an analysis of present Commission performance. As Wilson has noted, "neither industry nor the agencies have much need to fear major reforms, or at least reforms that reduce the item-by-item discretionary regulation that now exists.... With

respect to rate fixing agencies, a move towards greater reliance on market forces in industries where competition is adequate is also unlikely."[13] The reasons have to do mostly with economics: "Everyone who stands to pay more will naturally oppose deregulation and those who will pay less (consumers, future generations, some firms) are typically not organized to seek such benefits -- if, indeed, they are even aware of them."[14] In the case of the reforms proposed here, the natural gas pipeline companies and the electricity generating companies might well oppose them because they could have the effect of reducing regulatory benefits to them from "negative but insignificant" to "negative but highly significant." Moreover, the logical sequence of decision-making requires the examination of the possibility of new public enterprise at the transmission level of each of these industries. Even the posing of the questions on the relative efficacy of public enterprise "can be expected to bring screams of outrage from private energy companies. While they have been less than dependable in supplying power, they can always be counted upon to protest loudly against proposals which might interfere with their

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[13] James Q. Wilson, op. cit., p. 57.

[14] James Q. Wilson, idem.

conception of 'free enterprise'...."[15] These reactions -- normally effective to prevent regulatory reform -- may not appear at the present time, however. The performance of the Federal Power Commission has been consistently ineffective, and costly to consumers of gas and electricity, while the problems of coordination and planning in these industries have grown to crisis or "shortage" proportions. A new policy will have to be constructed, and the reforms proposed here, while fundamental, are not the most radical. Indeed, before the New England regional commission establishes a nationalized New England Power Authority, the reduction of the Federal Power Commission to one-quarter of its present scale -- dealing only with exorbitant electricity or gas transmission rates -- would seem to be a preliminary and conservative step. The Federal Power Commission ought not to do most of the things it is now doing, from regulating field prices to certifying hundreds of extensions and revisions of pipeline and power systems. The Commission ought to abandon its planning and "quality enhancing" regulatory activities from sheer default, and give them over to an Executive Office agency that could start anew. These steps would seem modest, and they make economic sense.

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[15] From a speech by Senator George McGovern of South Dakota before the Midwest Electric Consumers Association, Denver, Colorado, December 15, 1970, page 9.

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